March 22, 2021

Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms Long:

EB-2020-0290 – Ontario Power Generation Inc. – Payment Amounts 2022-2026 – Interrogatories

Please find, attached, interrogatories on behalf of the Consumers Council of Canada for Ontario Power Generation Inc. pursuant to the above-referenced proceeding.

Please feel free to contact me if you have any questions.

Yours truly,

Julie E. Girvan

Julie E. Girvan

CC: All parties

INTERROGATORIES FOR ONTARIO POWER GENERATION INC.

FROM THE CONSUMERS COUNCIL OF CANADA

RE: EB-2020-0290

2022-2026 PAYMENT AMOUNTS

A - ADMINISTRATIVE DOCUMENTS/GENERAL

A-CCC-1
Please provide a table setting out the following:

a) A list of all of the external consulting engagements and reports undertaken to support the Application;
b) Of the reports undertaken a list of those that have been filed as evidence and those that have not;
c) The projected overall costs of those engagements broken out by costs incurred to date and forecast costs;
d) An indication as to whether the work was subject to an RFP process. If the work was not, an explanation as to why not;
e) The terms of reference for the work;
f) An explanation as to why the consultants are in most cases engaged by Torys and not directly by OPG.

A1-CCC-2
Re: Exhibit A1/T3/S1
Please explain the extent to which OPG intends to update its Application to include 2020 actual data.

A1-CCC-3
Please provide a list of all internal audit reports undertaken since OPG's last payment amounts proceeding.

A1-CCC-4
Re: Exhibit A1/T3/S1/p. 3
The evidence states that during the IR term, OPG expects that the IESO will complete the final design and implementation phase of its Market Renewal Program ("MRP"). Given the inherent uncertainty associated with the final design and implementation of the MRP, this application does not include any rate-setting impacts resulting from the MRP. OPG intends to file a separate application to address any such impacts once the IESO has completed the detailed design phase an advanced the implementation phase of the MRP. OPG does not expect the MRP will require any changes to the structure of OPG's base payment amounts, but the HIM may need to be adjusted.

a) What relief is OPG seeking from the OEB at this time regarding its proposal to potentially open up the final Payment Amounts Order arising from the current Application?
b) Would this be subject to some form of materiality threshold?;
c) When does OPG expect to file this Application?;
d) Has OPG done any internal assessment regarding the potential impacts of the MRP on its payment amounts or other components of the current Application. If so, please provide that analysis.

A1-CCC-5
Re: Exhibit A1/T3/S2/p. 12
The evidence states that the stretch reduction of $71.7 million is incremental to the performance improvements required to achieve OPG's Business Plan. Customers will benefit from these "up-front" budget reductions, and OPG will bear the risk of any shortfall during the IR term. Please provide a detailed schedule setting out a list of the potential areas where OPG expects to achieve savings during the rate plan term and quantify those savings.

A1-CCC-6
Re: A1/T3/S2/p. 12
Please provide a schedule setting out all productivity initiatives/projects undertaken during the 2017-2021 IR term and the annual savings achieved through each of those initiatives.

A1-CCC-7
Re: Exhibit A1/T3/S2/p. 14
In the EB-2016-0152 Decision the OEB required OPG to report on an annual basis the Nuclear Performance measures set out in that Decision. Please file those reports for the years 2017-2020.

A1-CCC-8
Re: Exhibit A1/T3/S2/Attachment 1 and 2
OPG has filed its performance scorecards for both the Nuclear and Hydroelectric businesses. Please explain, in detail, to what extent executive compensation is tied to the scorecard results, historically, and on a go-forward basis.

A1-CCC-9
Re: Exhibit A1/T5/S1
Please provide the Corporation Organizational Chart that was in place prior to the reorganization undertaken in 2020.

A2-CCC-10
Re: Exhibit A2/T2/S1
The Business Plan sets out performance targets including a forced loss rate of 1% for Darlington and 3.5% for Pickering. Are these targets tied to incentive pay? If so, please explain in what way.

A2-CCC-11
Exhibit A2/T2/S1/pp. 3-4
The evidence states that during the Business Plan period OPG will advance its recently released Climate Change Plan:

a) Please provide a copy of that plan;
b) Please provide information regarding how OPG arrived at its climate change goal of net-zero carbon emissions by 2040. Please explain how the establishment of Atura Power, OPG's subsidiary is consistent with this goal;
c) Is this a corporate goal? Does the goal of net-zero carbon emissions by 2040 apply to both the regulated businesses?

A2-CCC-12
Re: Exhibit A2/T2/S1/p. 5, Exhibit A1/T1/S5 (Organization Chart)
The evidence states that as part of its realigned organizational structure OPG centralized engineering and other operations support groups across the former Nuclear and Renewable Generation business units, were combined under an Enterprise Operations organization. Additionally, OPG integrated major project execution responsibilities under the Enterprise Projects Organization (EPO) originally established in 2018 and amalgamated business development and other strategic activities under a new Enterprise Strategy Organization. OPG has also provided a new Organizational Chart. Please provide the following:

a) For Enterprise Operations, Enterprise Strategy and Enterprise Projects the overall budgets for 2020-2026;
b) For each of those units indicate whether they do work for the unregulated businesses an if so, the proportion of the overall budgets that is allocated to the unregulated businesses –those within OPG and its subsidiaries;
c) The expected savings to be achieved in 2021 with the reorganization.

A2-CCC-13
Re: Exhibit A2/T2/S1/p. 8
The evidence states the 2020-2026 Business Plan includes the actions taken to date by the company in response to COVID-19, including the through a generation plan that reflects a deferred Darlington refurbishment schedule and other associated changes in Darlington outages, and certain incremental expenditures being incurred I the course of the pandemic:

a) Please provide an estimate of all expected COVID-19 impacts for 2020 and 2021;
b) What is the expectation these impacts will go beyond 2021?
c) Please provide all of OPG's submissions made to the OEB as part of its Consultation on the Deferral Account (EB-2020-0133).

A2-CCC-14
Re: Exhibit A2/T2/S1/p. 10

The evidence states that the 2020-2026 Business Plan has been submitted for concurrence to the shareholder pursuant to the Memorandum of Agreement. Why is OPG not required to get concurrence from the shareholder prior to the filing of this Application which is derived from the Business Plan? When is the shareholder expected to respond? How could the shareholder's review of the Business Plan impact this Application or the underlying budgets?

A2-CCC-15
Re: Exhibit A2/T2/S1/p. 14
Please provide all materials provided to OPG's Board of Directors regarding approval of the 2020-2026 Business Plan and this Application.

A2-CCC-16
Re: Exhibit A2/T2/S1/p. 16
OPG does not seek recovery of the costs arising from any Pickering closure activities in this application and will record them in the Pickering Closure Cost Deferral Account pursuant to Regulation 53/05. Has OPG prepared a forecast of these costs? If so, please provide that forecast. When will OPG seek recovery of these costs?

A2-CCC-17
Re: Exhibit A2/T2/S1/p. 18
OPG plans to mitigate approximately 90% of the corporate and operations support costs tied to Pickering by 2026. How did OPG arrive the 90% goal?

A2-CCC-18
Re: Exhibit A2/T2/S1/p. 20
OPG has set initiatives to support the Business Plan targets. It has stated that in addition to the 2020 organizational realignment other initiatives include: Digital Strategy, Resource Optimization, Project Management and Real Estate and Workplace Transformation. Please provide the expected cost savings for each of these initiatives for each year of the rate plan term, 2022-2026.

A2-CCC-19
Re: Exhibit A/T2/S1/p. 21
OPG has retained Innovative Research Group (Innovative) to conduct a multi-phase customer engagement process to seek input from customers to help inform the company's Business Plan. Was this work subject to an RFP process? If not, why not. Please provide the following:

a) The Terms of Reference for the work;
b) The total cost of the work and how it is to be recovered;
c) A detailed description of OPG's role in the customer engagement undertaken by Innovative;
d) A detailed description of Torys role in the customer engagement undertaken by Innovative;

e) An explanation as to how OPG selected the initiatives and projects that were put to customers for their input.

A2-CCC-20
Re: Ex. A2/T2/S1/p. 21
OPG has retained Innovative Research Group (Innovative) to conduct a multi-phase customer engagement process to seek input from customers to help inform the company's Business Plan. In undertaking the Innovative customer engagement work please explain why the customers views were not sought on the following:

a) The fact that embedded in the payment amounts is a return on equity of over 8%;
b) The fact that OPG is seeking to increase the amount of equity in its capital structure to 50% which will increase the payment amounts;
c) The fact that OPG is embarking on an initiative to develop a Small Modular Reactor at the Darlington site and will incur over $270 million in 2020 and 2021 for preliminary planning and preparation of the SMR.

A2-CCC-21
Re: Exhibit A2/T2/S1 and 2019 Annual Report
In the 2019 Annual Report it states that OPG will be a leading energy innovation company, advancing clean technologies and solutions to help the markets where we operate achieve net-zero carbon economies by 2050. This includes being the catalyst for efficient, economy wide decarbonization, nurturing new industries and new careers for Ontarians, ensuring province-wide chargers for electric vehicles, advancing the potential for vehicle grid integration and by making sure customers benefit from electrification. As part of this OPG plans to facilitate the transition of two million electric vehicles to Ontario's roads through electrification. OPG also entered into a partnership with Hydro One to develop the Ivy Charging network.

a) Please indicate which business unit is involved in developing the EV projects referred to above;
b) Is OPG seeking any relief through this Application regarding EVs and grid integration.

A1-CCC-22
Re: Exhibit A1/T11/S1/ Attachment 1, p. 17
As illustrated in Figure 4 above, and in alignment with IESO's long term outlook, OPG's forecast of the declining presence of SBG conditions points to a significantly lower expected SBG spill over the 2021 to 2026 period.

a) Please provide a forecast of the net annual cost of Surplus Baseload Generation OPG expects to track in the Hydroelectric Surplus Baseload Generation Variance Account based on the forecast of SBG in Figure 4 of the Surplus Baseload Generation Study.

B - RATE BASE

B1 – Working Capital

B1-CCC-23
Re: Exhibit B1/T1/S 2/ p. 3
The proposed cash working capital amount calculated based on the results of the Navigant Study of ($37.8M) is lower than the average amount of $17.2M reflected in the previous four nuclear payment amounts applications.

a) Please explain the driver(s) of the proposed negative working capital amount for the test year, relative to the average positive working capital amount in the previous four nuclear payment amounts applications.

C - CAPITALIZATION, COST OF CAPITAL AND NUCLEAR LIABILITIES

C1-CCC-24
Re: Exhibit C1/T1/S1/p. 2
The Application incorporates an ROE of 8.34% as this is the latest rate published by the OEB pursuant to the ROE formula as set out in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 2009.* This will be updated as of the effective date of the Payment Amounts Order. OPG is proposing to use the same ROE throughout the IR period:

a) What would be the impact on the 2022 Revenue Requirement if the ROE was reduced by 100 basis points?;
b) Did OPG consider adjusting the ROE pursuant to the formula in each year of the IR period? If not, why not?
c) If the OEB undertakes a Generic Cost of Capital Review during the IR period, will OPG seek to change the ROE embedded in the Payment Amounts? Please explain your answer.

C1-CCC-25
Re: Exhibit C1/T1/S2 – Concentric Report
Torys has retained Concentric Energy Advisors to prepare a Common Equity Ratio Study on behalf of OPG:

a) Was this work subject to an RPF? If not, why not?
b) Please describe the roles OPG Staff and Torys had in the preparation of the Concentric Report

C1-CCC-26

Re: Exhibit C1/T1/S1
Please set out the allowed ROE and actual ROE for each year 2017-2021. Please provide a detailed variance analysis.

C1-CCC-27
Re: Exhibit C1/T1/S1
OPG is requesting approval to increase the level of equity in its capital structure to 50%. Please recast Tables 1-5 assuming the currently equity level of 45% is maintained. What would be the impact on the revenue deficiency each year assuming the current level of 45 % is maintained?

C1-CCC-28
Re: Exhibit C1/T1/S2/Table 7a
OPG has planned Long-term Debt Issues for 2021. Please provide an update once these have been completed.

C2-CCC-29
Re: Exhibit C2/T1/S1/ pp. 2-3; Ex. C2/T1/S1 Attachment 3 Table 1
The treatment of Pickering EOL dates is discussed in further detail in Ex. F4-1-1, Section 3.5 and Ex. H1-1-1, Section 6.2. As noted in those exhibits, OPG is applying for a deferral account related to future changes to Pickering station EOL dates for accounting purposes, including associated impacts on nuclear liabilities, as part of this application in line with the OEB's current accounting order requirements, effective January 1, 2021. This includes changes to the Pickering station EOL dates expected effective December 31, 2020, the impact of which cannot be determined pending finalization of the corresponding year-end 2020 adjustment to the nuclear liabilities and therefore has not been reflected in this application. This adjustment will be reflected in OPG's 2020 audited consolidated financial statements to be issued in March 2021.

a) Please update Ex. C2/T1/S1 Table 1 to reflect the complete actual and forecast annual Nuclear Liability costs including costs tracked or proposed to be tracked in deferral accounts (CCC presumes that, for example, the unaccounted-for Pickering station EOL related adjustments will be available at the time interrogatory responses are prepared).

C2-CCC-30
Re: Exhibit C2/T1/S1/ Attachment 2, p. 10, 33, 176; Ex. C1/T1/S1 Attachment 3 Table 1.
We found a wide range of practices with respect to nuclear decommissioning cost recovery. We have organized the practices we identified into four broad methodologies, as follows:

3) Flow through cost. This method "passes" through to consumers the fees or levies payable by utilities to other parties in exchange for these parties effectively discharging the utilities' obligations for nuclear decommissioning or, more often, for waste management and spent fuel management.

Based on a flow through cost

This method "passes" through to consumers the fees or levies payable by utilities to other parties in exchange for these parties effectively discharging the utilities' obligations for nuclear decommissioning or, more often, for waste management. Such fees or levies may be treated as operating expenses and recovered as such in the normal course through cost-based price setting.

Screening Analysis

As noted in Section 3.7, we identified four major categories of rate recovery methods: (1) forward looking funding requirement; (2) accounting expense; (3) flow through; (4) arbitrary rate.

We have performed a screening analysis of these four methods considering the most prevalent rate recovery methods identified in the jurisdictions most similar to OPG using the jurisdictional characteristics (as discussed in Chapter 3). Although we have attempted to identify the aspects of each cost recovery method that may apply to OPG, in comparing OPG's nuclear liabilities cost recovery methodology to methodologies encountered in other jurisdictions, the unique circumstances of each entity must be considered.

Based on this screening analysis, the two recovery methods most likely to be applicable to OPG are the forward looking funding requirement and the accounting expense. These methods appear to be common in jurisdictions subject to economic regulation. The flow through method and the arbitrary rate methods are not broadly applicable rate recovery methods.

a) Please provide details of the "screening analysis" that led to the conclusion that the flow through method would not be analyzed within section 28.3 of the Nuclear Liability Cost Recovery Jurisdictional Study;
b) Please identify any fundamental barriers that would prevent the OEB from considering the flow through method for OPG's nuclear liabilities;
c) Please provide a version of Ex. C1/T1/S1 attachment 3 Table 1 that illustrates OPG's historical and forecast Nuclear Liabilities on a flow through basis. In doing so please include all costs tracked or proposed to be tracked in deferral accounts (CCC presumes that, for example, the unaccounted-for Pickering station EOL related adjustments, to the extent that they affect OPG's flow through costs, will be available at the time interrogatory responses are prepared);
d) Please describe and, to the extent possible, quantify the transitional issues OPG believes would need to be resolved if the OEB were to require Nuclear Liabilities to be accounted for on a flow through basis going forward.

C2-CCC-31
Re: Exhibit C2/T1/S1/ pp. 18, 19.
Through the calculation of regulatory income taxes for the prescribed facilities, the nuclear revenue requirement includes income tax impacts associated with the above cost elements for

the nuclear liabilities, as well as the tax impacts of the prescribed facilities' contributions to the segregated funds, expenditures on nuclear liabilities and disbursements from the segregated funds.

As further described in Ex. F4-2-1, sections 3.2.1, 3.2.2 and 3.2.6, the cost components of the prescribed facilities' revenue requirement methodology (depreciation, nuclear waste management variable expenses and return components) are not tax deductible and therefore attract a tax gross-up cost. As described in Ex. F4-2-1, sections 3.2.3 and 3.2.4, contributions to the segregated funds and both ONFA-funded and internally funded expenditures on nuclear liabilities are deductible for income tax purposes in accordance with regulations under the Electricity Act, 1998, while the disbursements from the segregated funds to cover the ONFA-funded expenditures are correspondingly taxable. The income tax effects of these components are included in the nuclear liabilities' revenue requirement impact at Ex. C2-1-1 Table 1, line 7, as calculated in Ex. C2-1-1 Table 1a, Note 2.

a) Please confirm whether the prevailing methodology for the prescribed facilities, as compared to an alternative flow through method, has the disadvantage of attracting a tax-gross up amount as a result of the non-tax deductible nature of several of its elements, or whether the current methodology and an alternative flow through method are equivalent in terms of their tax impacts on rates.

D - CAPITAL PROJECTS

D2 – Darlington Refurbishment Program

D2-CCC-32
Re: Exhibit D2/T2/S 10/ pp. 39-41, p. 110-111
When OPG determined to proceed with planning for DRP it investigated alternative solutions for addressing heavy water storage. Two approaches were considered: construction of a new building at a different location at or around Darlington, and adding storage to an existing Darlington building. During development of the 2012 Full Release Definition BCS (discussed below in Section 13.3) (see Attachment 2m), two additional alternatives were considered: limiting the project to the 1,700 m3 required to support refurbishment and construction of a drum warehouse to hold the approximately 7,200 drums that would be required to store the heavy water drained from two units undergoing overlapping refurbishment.

The 2015 Superseding Release Execution BCS also analyzed three alternatives for completing the project in light of its progress to date and compared them to the preferred alternative (Alternative 1).

a) Please confirm that the alternatives described in Ex. D2/T/2/S 10/ pp. 39-41 and 110-111 comprise all of the alternatives to the D20 Storage Project that OPG considered. If additional alternatives were considered, please provide details of those alternatives including when they were considered, the estimated cost of those alternatives, and the reasons why those alternatives were rejected;

b) Please confirm that the alternatives detailed in Ex. D2/T/2/S 10/ pp. 39-41 were all considered in relation to the D20 Storage Project at an estimated cost of $108.148M pursuant to the 2012 Full Release Definition BCS, and that the alternatives detailed in Ex. D2/T/2/S 10/ pp. 110-111 were all considered in relation to the D20 Storage Project at an estimated cost of $381.1M pursuant to the 2015 Superseding Release Execution BCS;

c) Please advise which, if any, of the examined alternatives to the D20 Storage Project would, as compared to the total claimed cost of $510M, have been preferable had the full cost of the D20 Storage Project been known at time the alternatives were considered. If none of the alternatives would have been preferable despite the final cost of the D20 Storage Project please explain why not.

D2-CCC-33

Re: Exhibit D2/T2/S11/ Attachment 3, pp. 5, 44

This report presents our cost estimate for the engineering design, procurement, construction, and commissioning of the D2O Storage Project, as it would have been calculated before construction began. The cost estimate assumes what might be called “perfect knowledge” with respect to project scope, design requirements, and actual site conditions encountered. The estimate comprises the cost to pay a construction contractor to engineer, procure, and construct (“EPC”) the D2O Storage Project, and OPG’s in-house cost (“owner’s cost”) for contract administration, procurement support, and engineering oversight and approval through project turnover, commissioning, and contract close-out, but does not include any costs associated with post-commissioning operations and maintenance (“O&M”).

a) Please confirm that Bates White Economic Consulting was provided with full details of OPG’s actual costs to bring the D20 Storage Project into service and a full description of the issues experienced by OPG during the course of bringing the D20 Storage Project into service as a result of having received the 507 documents listed at Appendix B of its study prior to Bates White Economic Consulting developing its own cost estimate.

b) Please confirm that Bates White Economic Consulting was not asked to and did not consider alternatives to the D20 Storage Project in order to determine whether there were alternatives that, in light of Bates Economic Consulting’s cost estimate of the D20 Storage Project, may have been preferable.

c) Please confirm that Bates White Economic Consulting’s study does not purport to have examined OPG’s or OPG’s contractors’ actual performance in bringing the D20 Storage Project into service.

D2-CCC-34

Re: Exhibit D2/T2/S 11/ Attachment 3, pp. 5, 44

This report presents our cost estimate for the engineering design, procurement, construction, and commissioning of the D2O Storage Project, as it would have been calculated before construction began. The cost estimate assumes what might be called “perfect knowledge” with respect to project scope, design requirements, and actual site conditions encountered. The estimate comprises the cost to pay a construction contractor to engineer, procure, and construct ("EPC") the D2O Storage Project, and OPG's in-house cost ("owner's cost") for contract administration, procurement support, and engineering oversight and approval through project turnover, commissioning, and contract close-out, but does not include any costs associated with post-commissioning operations and maintenance ("O&M").

a) Please confirm that Bates White Economic Consulting was provided with full details of OPG's actual costs to bring the D20 Storage Project into service and a full description of the issues experienced by OPG during the course of bringing the D20 Storage Project into service as a result of having received the 507 documents listed at Appendix B of its study prior to Bates White Economic Consulting developing its own cost estimate.
b) Please confirm that Bates White Economic Consulting was not asked to and did not consider alternatives to the D20 Storage Project in order to determine whether there were alternatives that, in light of Bates Economic Consulting's cost estimate of the D20 Storage Project, may have been preferable.

D2-CCC-35
Re: Exhibit D2/T2/S 10/ pp. 2-3, 65
The evidence also explains how the risks and complexity of the project were underestimated by two experienced nuclear industry contractors retained to engineer, procure materials for and construct the project. Both contractors significantly under-forecast the project's duration and cost. The first of the two contractors was terminated by OPG based on performance. The second contractor ultimately agreed to complete the project for a maximum price that was tens of millions of dollars lower than the contractor's final cost to complete the project.

By spring 2014, with the project schedule extending and cost rising, OPG became increasingly dissatisfied with B&M's performance on the D2O Storage Project. The failure to meet the schedule for delivery of design documents and the delay in completing the LPSW relocation had pushed the construction schedule and increased costs. OPG was having difficulty getting B&M to commit to a new schedule and a firm estimate of cost at completion. Moreover, with the move into the excavation phase of the project, OPG also observed that the working relationship between B&M and EllisDon, which was responsible for both excavation and construction of the seismic dike, was not well-coordinated. In addition, the schedule delay meant that construction of the seismic dike would occur during winter, exposing the project to additional weather delays.

a) Please quantify the "increased costs" associated with B&M's performance issues that ultimately led to the termination of the B&M contract. Please discuss the extent to which any such increased costs have been included in the applied for D20 Storage Project costs sought for recovery.

D2-CCC-36
Re: Exhibit D2/T2/S 10/ p. 69

In September 2014, OPG convened a series of meetings with B&M as a final attempt to reach a firm agreement on cost and schedule for the D2O Storage Project. OPG had concluded that unless B&M assumed greater risk for the cost of the completed project, there could be no cost certainty. B&M and its Tier 1 subcontractors were willing to set a target price for completion and reduce their recovery of the performance fee under the ESMSA if the target price was exceeded. However, they were unwilling to assume any financial responsibility for cost overruns if the project's cost exceeded the target price.

. . .

Negotiations with B&M continued into October. B&M offered the additional concession of eliminating the performance fee in the event the target price was exceeded, but remained unwilling to accept any responsibility for increases in the target price itself. OPG continued to reject this approach.

a) Please provide the target price under the B&M ESMSA that B&M was willing to accept in relation to their performance fee but were unwilling to accept responsibility for in the event there were increases in the target price.

D2-CCC-37

Re: Exhibit D2/T2/S 10/ p. 79

The increased weighting of technical merit in this work request, as compared to the first work request issued in 2012, reflected the fact that as design, engineering and construction progressed, the project's complexity was better understood. As a result, OPG assigned greater weight to the technical aspects of the work request.

a) Please explain why it would not be the case that the less a project's complexity was understood by OPG, the more important the technical aspects in a work request would be.

D2-CCC-38

Re: Exhibit D2/T2/S10/ p. 91.

In October 2016, CanAtom issued Project Change Notice ("PCN") 67. This PCN sought a cost increase of $37.4M for engineering redesign and delays to procurement and construction arising primarily from the changes to the building's steel superstructure and the ground level (elevation 100 m) slab atop the seismic dike. This notice was OPG's first indication of the magnitude of the additional cost claim, despite frequent reports from CanAtom on the status of the project.

In addition to the funds requested by PCN 67, by December 2016, CanAtom had issued several other smaller PCNs, which together totaled about $7.5M. Thus, by the end of 2016 CanAtom was claiming some $45M in additional costs.

A series of meetings occurred early in 2017 to better understand the basis for CanAtom's cost claims and to explore ways to jointly mitigate them. Through commercial discussions between the parties, OPG accepted responsibility for about $7.5M for claims related to scope or estimation issues, leaving some $37.5M in dispute. This sum related primarily to redesign of the steel superstructure and seismic dike top slab.

OPG refused to accept the costs of the redesign. OPG's position was that it had agreed to the redesign based on the CanAtom's confirmation that it would not adversely impact the project's cost and schedule and, in any event, the engineering and project management costs claimed were excessive. As noted previously, OPG also took the position that since this design change occurred before finalizing the SOW underpinning the PO with CanAtom for the project, all costs related to the design change were already included in the negotiated PO amount.

a) Please quantify how much of the $37.5M redesign costs that OPG refused to accept were ultimately paid for by OPG and included in the D20 Storage Costs put forward for approval. Please explain the rationale for any such costs put forward for approval.

D2-CCC-39
Re: Exhibit D2/T2/S10/ p. 102
Construction completion was achieved in November 2019. At that time, almost all of the systems, equipment and the above ground portions of the building itself were placed into service. Additional monitoring and control systems and other miscellaneous equipment were placed in service in 2020 and the building was declared ready to accept heavy water.

At year-end 2019, CanAtom prepared an estimate of its cost to complete the D2O Storage Project. Using the $70M maximum guaranteed payment and an additional $1.9M that OPG had agreed to pay for changes to project scope and a settlement of CanAtom claims to year end 2019. CanAtom estimated its total cost at year-end 2019 to be $148.9M. This figure comprised $145.5M in accrued costs plus approximately $3.4M in pending or forecast costs. Given the maximum cost contract, CanAtom calculated its loss on Phase 2 work at approximately $77M as of year-end 2019.

a) Relative to the total claimed D20 Storage Project claimed capital costs of $509.3M, please break out the total amount paid to B&M, the total amount paid to CanAtom, any incremental amounts claimed by B&M but not paid, and any incremental amounts claimed by CanAtom but not paid.

D – CAPITAL PROJECTS

D3-CCC-40
Re: Exhibit D3/T1/S1/p.6 and Table 1
The evidence states that in 2017 OPG entered into an Enterprise Agreement with Microsoft ("Microsoft Enterprise Agreement", which allows OPG to obtain per user software licenses for Microsoft E5. The new model shifts away from the purchase and implementation of individual software as it became obsolete to entering in to term agreement with Microsoft. As such OPG will no longer require individual, small projects for each product licence and will, instead,

renegotiate and renew its agreement with Microsoft every three years. The IT Support services are increasing significantly beginning in 2020 and continuing into the IR term:

a) Please provide the Business Case Analysis for the changes resulting from the Microsoft Enterprise Agreement;
b) Please indicate why the IT Support Costs are increasing during the IR term. For example, the increase from 2019 to 2022 is almost double going from $53.1 million to $91.2 million.

D3-CCC-41
Re: Exhibit D3/T1/S1/p. 7
OPG has set out its Real Estate strategy to the end of 2026. The intent is to reduce its overall real estate footprint by optimizing the layout of its offices through workplace transformation and by investing in a new, sustainable corporate campus too consolidate non-plant employees at a principal location in Clarington. Did OPG retain outside consultants to assist in maximizing the most cost-effective strategy. If not, why not?

E – PRODUCTION FORECAST

E2-CCC-42
Re: Exhibit E2/T1/S1/ p. 1
OPG is seeking approval of a nuclear production forecast of 33.2 terawatt-hours ("TWh") for 2022, 30.8 TWh for 2023, 33.3 TWh for 2024, 30.2 TWh for 2025, and 21.5 TWh for 2026. This amounts to a total 149.1 TWh nuclear production forecast for the IR term.

a) Please provide, in table form, the OEB approved production forecast and the actual production for each year from 2017 to 2020, including both the total production forecasts and actuals and the production forecast and actual for each unit, as well as the annual revenue impact of the differential between the OEB approved and actual forecasts.

E2-CCC-43
Re: Exhibit E2/T1/S1/ p. 4
Chart 2: Planned Outage Durations.

a) Please provide the OEB approved planned outage days, the actual planned outages, and the unbudgeted planned outages both in total and for each unit from 2008 to 2026 (recognizing that 2021-2026 will include only forecast numbers), including FEPO days. Please include the revenue impact of the variance in outage days between OEB approved and actuals.

E2-CCC-44
Re: Exhibit E2/ T/1/S1/ pp. 11-12
3.2.2 Vacuum Building Outage

A six-unit Pickering VBO is scheduled in 2022. Historically, OPG has undertaken VBOs at Pickering on an established 10-year regulatory test interval. The initial VBO date was 2020 to be consistent with the established 10-year regulatory test interval from the last execute VBO in April 2010. Based on innovative maintenance and inspection activities and after extensive technical reviews, the CNSC accepted OPG's request in March 2019 to increase the interval from 10 to 12 years, allowing the VBO to be deferred until 2022.This twelve-year frequency is consistent with the frequency used at Darlington.

a) Please confirm that the impact of the 6-unit Pickering VBO was included in the outage forecast for 2021 in EB-2016-0152, such that OPG's rates for 2021 were increased to account for the outage in that year;
b) Please confirm that moving the VBO outage to 2022 has the effect of reducing the production forecast for 2022, necessitating an increase in 2022 rates;
c) Please confirm the number of outage days included in the OEB approved number of 2021 outage days as a result of the VBO, and the number outage days OPG is seeking approval for in 2022 as a result of the deferral of the VBO to 2022;
d) Given the 10-12 year frequency of testing cited by OPG, please explain the benefit to ratepayers of initially increasing rates in 2021 to account for the impact of the VBO, shifting the VBO to 2022, and then accounting for VBO in 2022 a second time
e) Please provide the revenue impact of including the VBO in 2021 without incurring those outages, and the rate impact of including VBO in 2022.

F – OPERATING COSTS

F4-CCC-45
Re: Exhibit F4/T3/S1/ Attachment 2 p. 13; EB-2016-0152 Ex. F4/T3/1/ Attachment 2 p. 11
[2019 Study]
Total Remuneration Analysis Results
OPG is positioned relative to market as follows:

- Total direct compensation at 5.2% above
- Total remuneration excluding PTO at 10.2% above
- Total remuneration at 7.7% above

[2015 Study]
Overall, OPG's Total Direct Compensation is positioned within 5% of the target market.

a) Please confirm that the 2019 total direct compensation result of 5.2% for OPG as a whole and the 2015 total direct compensation result of "within 5%" for OPG as a whole are comparable but for the use of the 75th percentile for a portion of the Nuclear Authorized Segment in the 2015 study. If not confirmed, please confirm that the two results are directly comparable in terms of methodology or explain all the differences between the two methodologies used.

b) To the extent necessary please adjust the 2015 result of “within 5%” for OPG so that it is comparable to the 2019 result; by way of example, if the two results are identical in methodology but for the use of the 75th percentile for a portion of the Nuclear Authorized Segment in the 2015 study, please adjust the 2015 result using the 50th percentile for the Nuclear Authorized Segment.

c) Subject to adjusting the 2015 result to match the methodology used in the 2019 study as required, the results seem to suggest that OPG’s benchmarking results are either flat or slightly worsening over time; please comment on whether that is the case, and if not, explain how OPG’s benchmarking results have improved between 2015 and 2019 with respect to total direct compensation.

d) With respect to the three results from the 2019 study of 5.2%, 10.2%, and 7.7%, please provide, for each employee category (PWU, Society, Management, and Total), the cost impact if OPG was at exactly the 50th percentile under each of those 3 measures. Please only include the cost impact as they relate to costs that either directly attributable or allocated to the nuclear facilities. CCC notes that OPG provided a similar analysis in EB-2016-0152 at Exhibit L-6.6 Schedule 15 SEC-083, with the details of the analysis being provided at Exhibit JT 3.2.

F2 – NUCLEAR

F2-CCC-46
Re: Exhibit F2/T2/S1/Tables 1-2
Please recast Tables 1-2 – Base OM&A – Nuclear to include 2020 actual amounts

F2-CCC-47
Re: Exhibit F2/T8/S1/pp. 1-5
OPG is forecasting OM&A expenses of $66 million in 2020 and $206 million for a Small Modular Reactor at the Darlington Site:

a) Please provide a detailed breakdown of the costs related to Technology Developer Selection ($190 million), Licensing ($20 million) and Project Development and Oversight ($62 million);
b) Please provide a complete list of all costs incurred to date;
c) Please provide the Memorandum of Understanding signed by the provinces of Ontario, New Brunswick, Saskatchewan, and Alberta on August 12, 2020. Please describe the nature of the collaboration between the provinces;
d) Please provide all correspondence between OPG and the Province of Ontario regarding the development of SMRs;
e) Please provide all OPG internally prepared and externally prepared reports produced regarding the development of SMRs;
f) Please indicate whether OPG has undertaken any cost-benefit analysis regarding the development of SMRs. If, so please provide that analysis;

g) Please indicate what relief, if any OPG is seeking from OPG regarding the SMR project through this Application.

F2-CCC-48
Re: Exhibit F2/T8/S1/p. 1 – 2019 OPG Annual Report, p. 9
In the 2019 Annual Report (p. 9) there is reference to the following: OPG's goal is to deploy at least one SMR facility in Ontario, and support deployment of two in other Canadian jurisdictions that currently rely on coal:

a) Please explain what is meant by the comment OPG will "support" deployment of two SMRs in other Canadian Jurisdictions that currently rely on coal;
b) Will these activities by undertaken by the regulated operations, the unregulated operations within OPG or through an affiliate? Please explain;
c) Please explain why Ontario ratepayers should be required to fund the development of SMR facilities outside of Ontario.

F3 – CORPORATE SUPPORT SERVICES

F3-CCC-49
Re: Exhibit F3/T1/S4
OPG currently has three operating subsidiaries – Alura Power, Laurentis Energy Partners and Eagle Creek Renewable Energy:

a) Please provide the Service Level Agreements between OPG and each of its subsidiaries.;
b) Please describe, in detail, the services OPG provides to each of the subsidiaries;
c) Do these subsidiaries provide services to OPG? If so, please describe these services;
d) Will the corporate allocations and asset service fees change over the IR term? If so, on what basis;
e) Does OPG currently have any plans to establish any other subsidiaries during the period 2022-2026? If so, please explain what is planned.

F3-CCC-50
Re: Exhibit F3/T1/S4
OPG has retained Elenchus to review OPG's Cost Allocation Policies:

a) Please provide the Terms of Reference for the Elenchus Study;
b) Please provide a timeline for the preparation of the Elenchus Study;
c) Please indicate whether Elenchus simply reviewed OPG's approach to cost allocation or was asked to propose alternative approaches;
d) Who initially developed OPG's cost allocation policy?

F4 – Other Operating Costs/Compensation/Centrally Held Costs

F4-CCC-51
Re: Exhibit F4/T4/S1
Centrally held costs are directly assigned or allocated to OPG's regulated operations using the same methodology approved in previous cases - subject to updates and refinements made to the methodology since EB-2016-0152 reviewed by Elenchus. One of the categories of centrally held costs are performance incentives. In deriving the forecast of performance incentives for the test period what assumptions have been made regarding the level of incentives achieved? Please describe, in detail, the methodology for deriving the incentive forecasts.

G - OTHER REVENUES

G2-CCC-52
Re: Exhibit G2/T1/S1/pp. 1-3
OPG currently produces Cobalt -16 at Pickering (Units 6,7 and 8) for use in the sterilization of surgical and medical supplies. How are the revenue forecasts derived and how are they treated in the IR plan? Why has the forecast been redacted? What relief is OPG seeking through this Application regarding the production of Cobalt-60 at Darlington? Please explain why Total Non-Energy Revenues are so much higher in 2024 and 2026 relative to 2022?

G2-CCC-53
Re: Exhibit G2/T1/S1/pp. 1-3
With respect to Heavy Water sales please provide the forecast and actual amounts for the period 2017-2021.

H – DEFERRAL AND VARIANCE ACCOUNTS

H1-CCC-54
Re: Exhibit H1/ T/1/S1/ p. 40
Impact Resulting from Optimization of Pickering Station End-of-Life Dates
Deferral Account

OPG proposes the deferral account because it anticipates that there will be future changes to the Pickering station EOL dates, for financial accounting purposes in accordance with US GAAP, once necessary criteria are met. In particular, this includes the accounting EOL date for Pickering Units 5-8, which is expected to be reassessed in the future when further technical work and the status of the CNSC's approval process are considered to provide sufficient high confidence, for depreciation purposes, with respect to the planned operation of the units beyond the current EOL date of December 31, 2024.

a) Please confirm that EOL dates assumed for all Pickering units for the purposes of setting all the related revenue requirement elements in the application, including forecast production.
b) Please confirm that the proposed deferral account only captures changes in the revenue requirement impact arising from changes to nuclear liabilities and depreciation and

amortization expense resulting from changes to the Pickering station EOL dates for OPG's prescribed nuclear facilities, and that there are no existing or proposed deferral accounts that capture any other impacts resulting from changes in the EOL dates for any of the Pickering units including forecast production.