From:	Calwell, Carolyn (ENERGY)
To:	Ronald Kwan
Cc:	Talwar, Shruti (ENERGY)
Subject:	FW: OPG 2018-2021 Business Plan
Date:	Tuesday, February 13, 2018 12:08:18 PM
Attachments:	OPG 2018-2021 BPlan w Transmittal.blord to mstr.18feb12.pdf

Hi Ron – wanted to get this over to you. Shruti will also share with staff. We are just beginning our review.

Carolyn

From: KING Catriona -OFFCORPSEC [mailto:catriona.king@opg.com]
Sent: February 12, 2018 7:14 PM
To: Thibeault, Glenn (ENERGY)
Cc: Imbrogno, Serge (ENERGY); Calwell, Carolyn (ENERGY); LYASH Jeffrey -PRESIDENT; Bernard Lord; LORD Bernard -BOARDCHAIR; HARTWICK Ken -FINANCE; ROWE Jennifer -CORPAFFAIRS
Subject: OPG 2018-2021 Business Plan

Dear Minister Thibeault,

Please see attached correspondence, sent on behalf of OPG Board Chair Bernard Lord, submitting OPG's 2018-2021 Business Plan for your concurrence, per the Memorandum of Agreement with the shareholder.
thx

Catriona King | Vice President, Corporate Secretary | **Ontario Power Generation Inc.**
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Good Governance is Good Business

ONTARIO POWER GENERATION

Bernard Lord
Board Chair

700 University Ave, Toronto, ON M5G 1X6

Tel: 416-592-2115
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

Highlights of the 2018-2021 Business Plan:

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

	Actual	Business Plan			
	2017	2018	2019	2020	2021
Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)*	859	995	968	764	1,160
Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)*	1,393	1,391	1,422	1,259	1,667
Return on Equity, excl. Fair Hydro Trust	7.7%	8.5%	7.7%	5.7%	8.1%
Debt Ratio, excl. Fair Hydro Trust*	34%	36%	33%	30%	26%
Enterprise Total Generating Cost *($/MWh)*	50.7	54.7	50.6	53.9	48.9
Production (net of Surplus Baseload Generation) *(TWh)*	73.8	72.4	74.5	70.6	71.0
OM&A Expenses from Ongoing Operations *($ millions)*	2,819	2,850	2,732	2,807	2,570
Capital Expenditures *($ millions)*	1,926	2,082	1,859	1,781	1,830
Total Headcount (Regular and Term Employees)	9,354	9,434	9,358	9,287	9,180

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

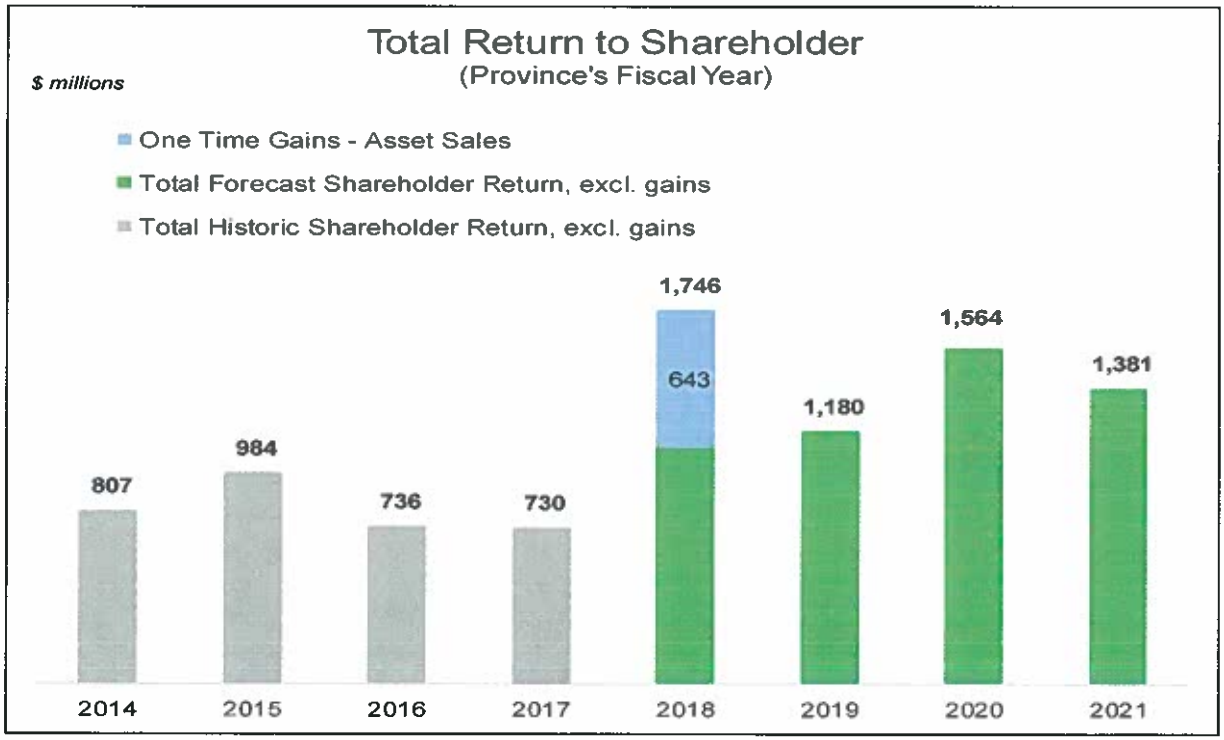
Total Shareholder Return

$ millions	2018*	2019	2020	2021	Total
Net Income Attributable to Shareholder	**1,195**	**795**	**1,053**	**877**	
Non Income Tax PILs					
GRC: Payable to OEFC	206	209	212	212	
GRC: Payable to MOF	103	101	103	103	
GRC: Payable to Niagara Parks Commission	7	7	7	8	
Property Tax Payable to OEFC	13	14	14	13	
Total Non Income Tax PILs	**330**	**331**	**336**	**335**	
Income Tax PILs	**221**	**54**	**175**	**169**	
Total Shareholder Return**	**1,746**	**1,180**	**1,564**	**1,381**	**5,871**
Improvement from 2017-2019 Business Plan	**528**	**4**	**307**	**-**	**838**

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.



While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

Critical Factors in the 2018-2021 Business Plan

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced CO_2 emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,

Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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OPG's 2018-2021 Business Plan

February 12, 2018

ONTARIO POWER GENERATION

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Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

2018-2021 Business Plan Summary	Actual	Business Plan			
	2017	2018	2019	2020	2021
Net Income Attributable to Shareholder *($ millions)*	860	1,043	1,066	919	1,373
Operating Net Income Attributable to Shareholder *($ millions)*	576	795	968	764	1,160
Total Return on Equity	7.6%	8.1%	7.2%	5.4%	7.1%
Operating Return on Equity	5.3%	6.8%	7.7%	5.7%	8.1%
Regulated Return on Equity	Average of 8.2% over the 2017 to 2021 period				
Debt Ratio, excl. Fair Hydro Trust*	34%	36%	33%	30%	26%
Enterprise Total Generating Cost *($/MWh)*	50.7	54.7	50.6	53.9	48.9
Production (net of Surplus Baseload Generation) *(TWh)*	73.8	72.4	74.5	70.6	71.0
OM&A Expenses from Ongoing Operations *($ millions)*	2,819	2,850	2,732	2,807	2,570
Capital Expenditures *($ millions)*	1,926	2,082	1,859	1,781	1,830
Total Headcount (Regular and Term Employees)	9,354	9,434	9,358	9,287	9,180

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

Key Assumptions and Risks

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

Net Income, Total Shareholder Return and Customer Price

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

Operations, Maintenance & Administration Costs

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

Production

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

Return on Equity and Capital Structure

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

Capital Investments and Business Development

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

Regulated Rates

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

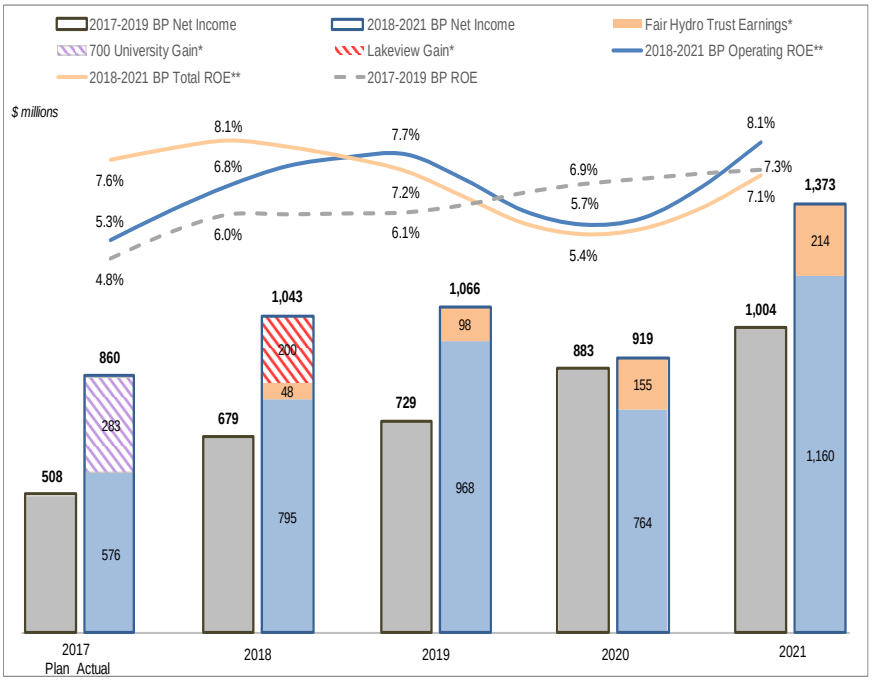
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

Net Income and Return on Equity

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.



* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

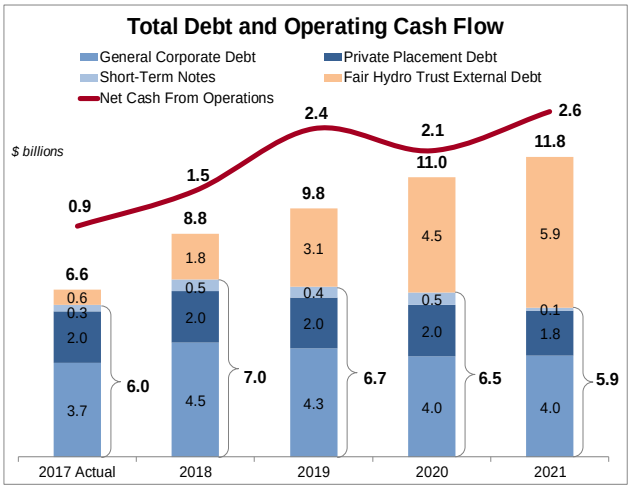
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

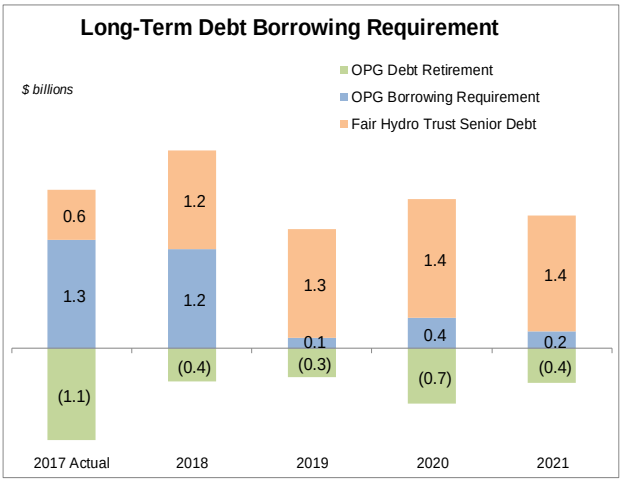
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

Financing and Liquidity



Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

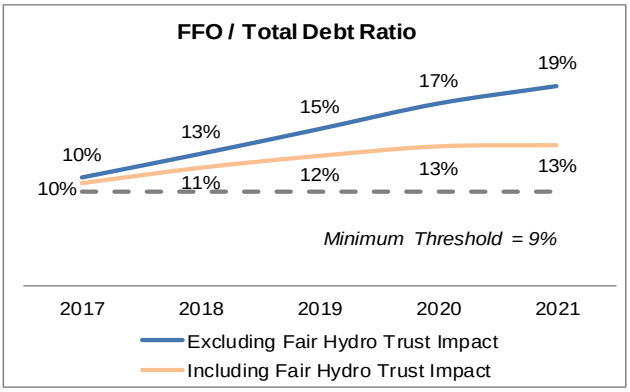


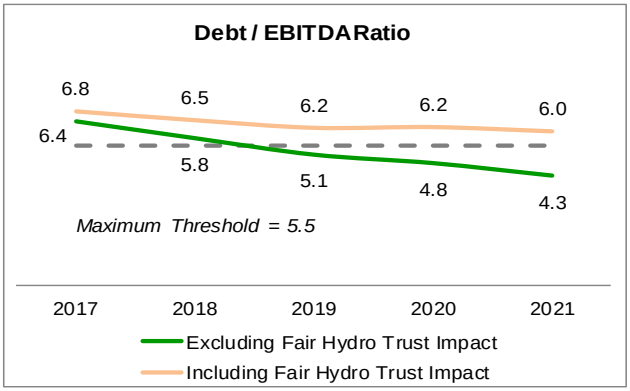
OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.





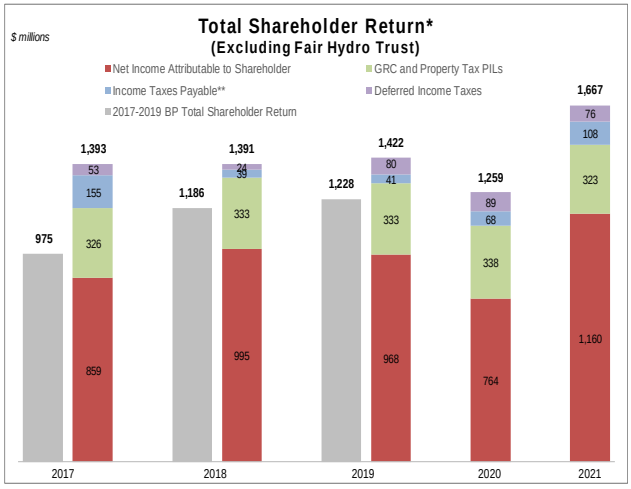
The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.



* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

Hydroelectric Operations

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

Safety

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

Environment

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

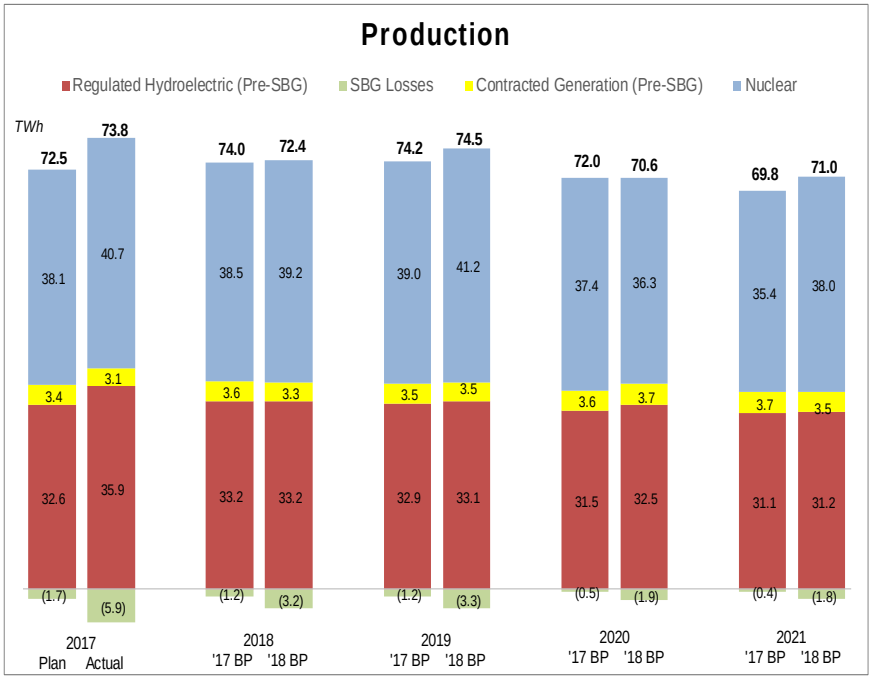
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

Production

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.



The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

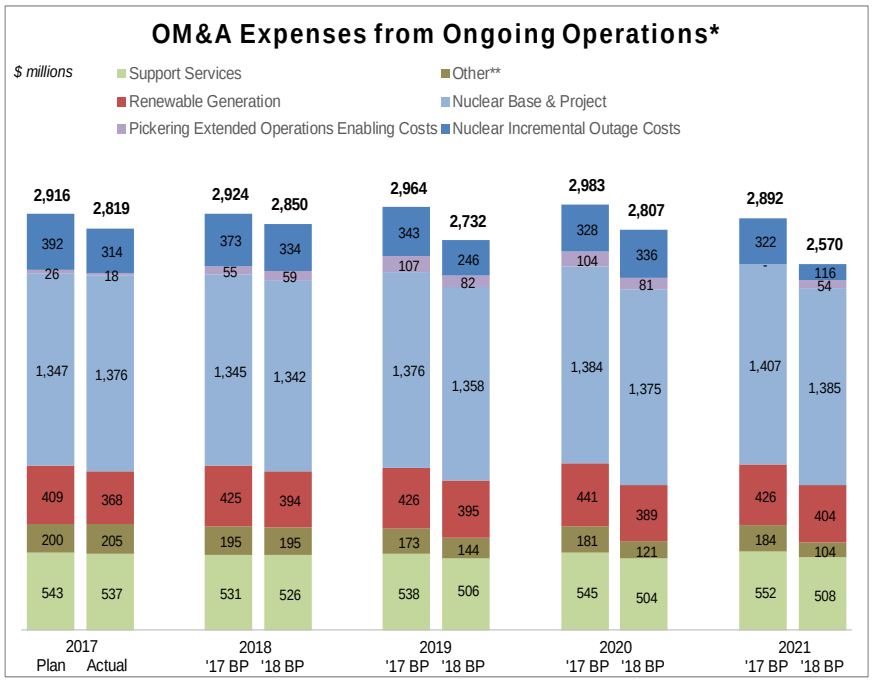
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

Operations, Maintenance & Administration Expenses

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative



* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

Pension and OPEB Costs

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

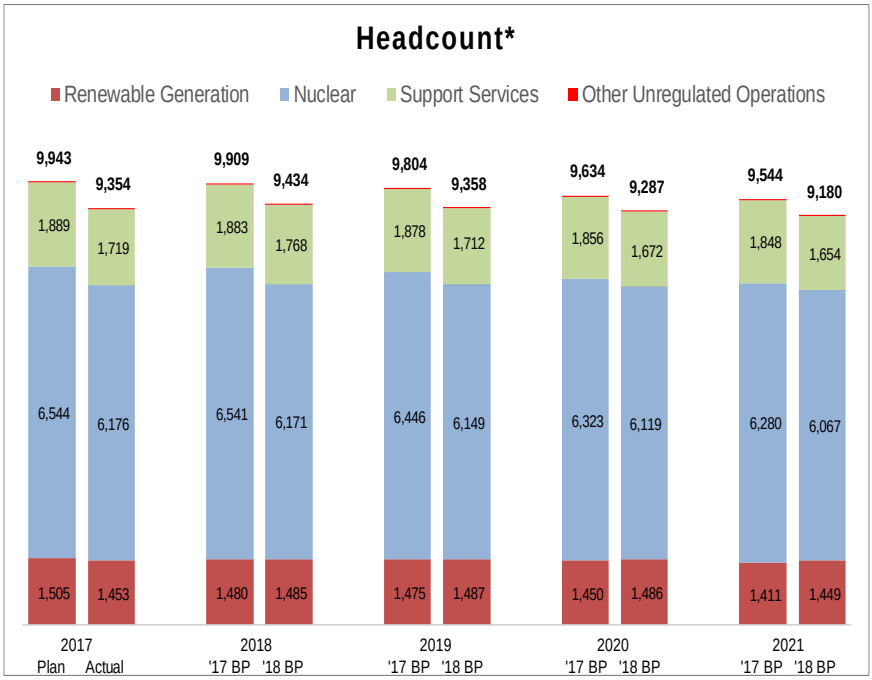
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

Headcount

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.



* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

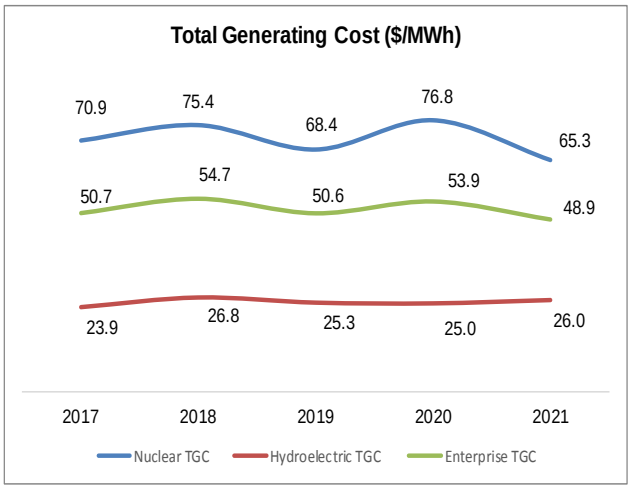
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

Total Generating Cost

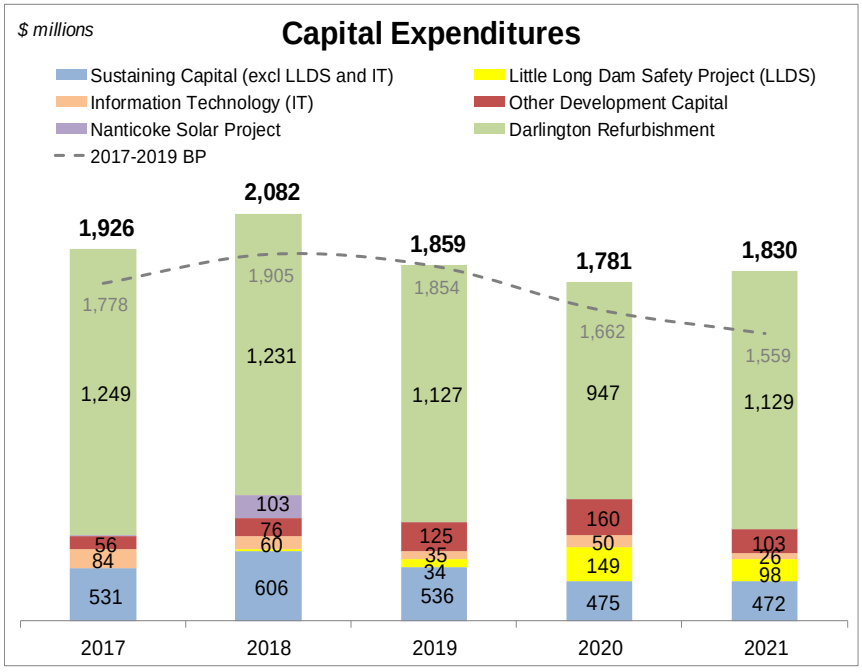
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.



Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.



In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

Darlington Refurbishment

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

Sustaining Capital

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

Business Development Capital

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

Provision Expenditures

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

Supporting Decarbonisation and Climate Change Goals

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

Pursuing Clean Energy Business Development Opportunities

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

Partnering with Indigenous Communities

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

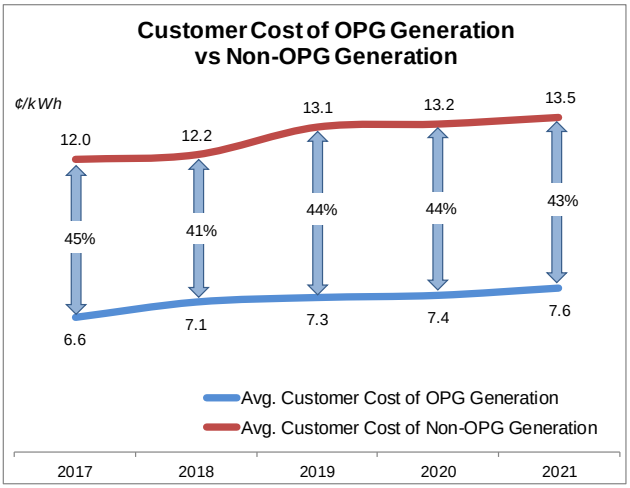
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

Expanding the OPG Brand and Creating a Diverse, Progressive Workforce

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

Moderating Electricity Prices and Contributing to the Economy



The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

APPENDIX 1: KEY PLANNING ASSUMPTIONS

Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

APPENDIX 3: Financial and Headcount Plan Information

Key Financial Metrics *(in millions of dollars unless otherwise noted)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Financial Performance Metrics					
Net Income Attributable to Shareholder	860	1,043	1,066	919	1,373
Operating Net Income Attributable to Shareholder	576	795	968	764	1,160
Earnings Before Tax	1,090	1,140	1,239	1,147	1,649
Total Return on Equity*	7.6%	8.1%	7.2%	5.4%	7.1%
Operating Return on Equity*	5.3%	6.8%	7.7%	5.7%	8.1%
Debt Ratio, excl. Fair Hydro Trust****	34%	36%	33%	30%	26%
FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)*	10%	11%	12%	13%	13%
FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact	10%	13%	15%	17%	19%
Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)*	6.8	6.5	6.2	6.2	6.0
Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times)	6.4	5.8	5.1	4.8	4.3
Total Debt at Year-End	6,579	8,757	9,768	10,978	11,777
Net Cash from Operations	944	1,460	2,384	2,067	2,642
Total Return to Shareholder, excluding Fair Hydro Trust Earnings***	1,393	1,391	1,422	1,259	1,667
Cost Performance Metrics					
Nuclear Total Generating Cost** *($/MWh)*	70.9	75.4	68.4	76.8	65.3
Hydroelectric Total Generating Cost** *($/MWh)*	23.9	26.8	25.3	25.0	26.0
Enterprise Total Generating Cost** *($/MWh)*	50.7	54.7	50.6	53.9	48.9
OM&A Expenses from Ongoing Operations	2,819	2,850	2,732	2,807	2,570
Darlington Refurbishment Capital Expenditures	1,249	1,231	1,127	947	1,129
Darlington Refurbishment In-Service Additions	305	24	335	4,698	-
Capital Expenditures excluding Darlington Refurbishment	677	851	731	834	700
In-Service Additions excluding Darlington Refurbishment	968	719	876	527	804
Nuclear Waste and Thermal Decom. Provision Expenditures	313	373	411	435	377

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

Operating Statement - Years Ended December 31 *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Electricity Generation Revenues	4,823	4,975	5,583	5,788	5,404
Fuel and Gross Revenue Charge	689	674	686	654	626
Generation Sales Gross Margin	**4,134**	**4,301**	**4,898**	**5,134**	**4,778**
Net Trading Margin	15	18	18	18	18
Non-Electricity Generation Gross Margin	302	258	249	253	235
Total Gross Margin	4,450	4,577	5,165	5,406	5,032
OM&A Expenses (excl. Cost of Goods Sold)	2,806	2,827	2,773	2,914	2,596
Depreciation and Amortization	679	743	1,139	1,318	950
Accretion on Nuclear Waste and Other Liabilities	960	991	1,023	1,055	1,091
Earnings on Nuclear Funds	(801)	(855)	(892)	(928)	(965)
Earnings from Fair Hydro Trust	(1)	(64)	(131)	(206)	(285)
Property Taxes	40	37	38	38	40
Restructuring	-	-	10	-	-
Total Expenses	3,683	3,679	3,961	4,191	3,426
Income before Interest and Other Income	**768**	**897**	**1,204**	**1,215**	**1,605**
Net Interest Expense	95	78	5	102	(9)
Other (Income)/Expense*	(417)	(320)	(40)	(35)	(35)
Income before Tax	**1,090**	**1,140**	**1,239**	**1,147**	**1,649**
Income Tax	209	79	154	209	255
Net Income	**881**	**1,061**	**1,085**	**938**	**1,394**
Net Income Attributable to Shareholder	**860**	**1,043**	**1,066**	**919**	**1,373**
Net Income Attributable to Non-Controlling Interests	21	18	19	20	21

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

Balance Sheet - As at December 31 *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Assets					
Current assets					
Cash and cash equivalents	234	273	354	249	301
Short-term investments	188	167	148	130	112
Accounts receivable	515	579	607	546	567
Fuel inventory	309	297	231	218	183
Materials and supplies	103	103	103	103	103
Other current assets	192	192	192	192	192
	1,541	1,612	1,635	1,438	1,458
Property, plant and equipment and intangible assets					
Fixed and intangible assets (net)	21,455	22,774	23,891	24,781	25,741
Other assets					
Financing Receivables	1,179	3,505	6,062	8,874	11,615
Nuclear fixed asset removal and nuclear waste management funds	16,724	17,473	18,233	19,009	19,811
Long-term materials and supplies	355	301	289	276	262
Regulatory assets (net)*	6,637	6,715	6,299	6,200	6,309
Investments subject to significant influence	309	301	291	278	263
Other long-term assets	28	28	28	28	28
	25,231	28,323	31,202	34,666	38,287
Total Assets	**48,228**	**52,709**	**56,727**	**60,884**	**65,486**
Liabilities					
Current liabilities					
Short-term notes payable	260	460	410	485	100
Accounts payable and accrued charges	1,228	1,140	1,092	1,072	1,238
Deferred revenue due within one year	12	-	-	-	-
Current income taxes payable	80	37	83	39	197
Long-term debt due within one year	398	368	663	413	153
	1,978	2,006	2,248	2,008	1,688
Long-term debt	5,921	7,929	8,695	10,080	11,524
Other liabilities					
Fixed asset removal and nuclear waste management liabilities	20,421	21,167	21,921	22,677	23,521
Pension liabilities (non-current)	3,423	3,353	3,275	3,195	3,098
Other post-employment benefit liabilities (non-current)	3,092	3,183	3,275	3,371	3,461
Long-term accounts payable and accrued charges	252	256	238	248	245
Deferred revenue	351	419	410	401	392
Deferred income taxes	879	904	984	1,073	1,149
	28,417	29,282	30,103	30,964	31,867
Equity					
Class A shares	519	1,540	2,664	3,899	5,105
Common shares	5,126	5,126	5,126	5,126	5,126
Retained earnings	6,396	6,957	8,024	8,942	10,316
Accumulated other comprehensive loss	(295)	(292)	(291)	(290)	(290)
Equity attributable to non-controlling interests	165	161	158	154	151
	11,911	13,493	15,681	17,832	20,407
Total Liabilities and Equity	**48,228**	**52,709**	**56,727**	**60,884**	**65,486**

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

OM&A Expenses by Business Unit *(in millions of dollars)*	Actual 2017*	Business Plan 2018	2019	2020	2021
Nuclear Operations	1,709	1,736	1,686	1,792	1,554
Renewable Generation	368	394	395	389	404
Other Unregulated Operations	2	2	2	2	2
Total Operations	**2,079**	**2,132**	**2,083**	**2,184**	**1,960**
Chief Administrative Office	171	177	170	169	172
Finance (incl. Chief Information Officer)	255	246	232	231	231
People & Culture	84	79	79	78	78
Corporate Office (inc. Corporate Affairs)	27	25	25	26	26
Total Support Services	**537**	**526**	**506**	**504**	**508**
Total Business Unit Expenditures	**2,616**	**2,658**	**2,590**	**2,688**	**2,468**
Insurance	36	40	42	45	46
Centrally Held Pension and OPEB	95	73	38	5	(15)
Other (incl. Cost of Goods Sold)	73	80	63	69	71
Total Ongoing Operations	**2,819**	**2,850**	**2,732**	**2,807**	**2,570**
OEB Variance and Deferral Account Offsets	(32)	(34)	49	80	14
Darlington Refurbishment Project	36	23	3	38	23
Nuclear New Build**	0	8	10	12	12
Total OM&A Expenses	**2,824**	**2,847**	**2,794**	**2,936**	**2,618**

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

Production *(TWh)*	Actual 2017	Business Plan 2018	2019	2020	2021
Darlington	*19.3*	*19.3*	*19.7*	*17.8*	*16.6*
Pickering	*21.4*	*19.9*	*21.5*	*18.5*	*21.4*
Total Nuclear	40.7	39.2	41.2	36.3	38.0
Regulated Hydroelectric	30.7	30.5	30.4	31.0	29.9
Contracted Generation Portfolio	2.5	2.7	2.9	3.3	3.1
Total Production (Net of SBG Losses)	**73.8**	**72.4**	**74.5**	**70.6**	**71.0**
Regulated Hydroelectric SBG Losses	5.2	2.7	2.7	1.5	1.3
Contracted Plant SBG Losses	0.7	0.6	0.6	0.4	0.5
Total SBG Losses	**5.9**	**3.2**	**3.3**	**1.9**	**1.8**

Headcount by Business Unit**	Actual	Business Plan			
	2017*	2018	2019	2020	2021
Nuclear	6,176	6,171	6,149	6,119	6,067
Renewable Generation	1,453	1,485	1,487	1,486	1,449
Other Unregulated Operations	6	10	10	10	10
Total Operations	**7,635**	**7,666**	**7,646**	**7,615**	**7,526**
Chief Administrative Office	572	599	575	558	556
Finance (incl. Chief Information Officer)	690	707	685	670	658
People & Culture	399	394	384	376	372
Corporate Office (incl. Corporate Affairs)	58	68	68	68	68
Total Support Services	**1,719**	**1,768**	**1,712**	**1,672**	**1,654**
Total Headcount	**9,354**	**9,434**	**9,358**	**9,287**	**9,180**

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

Provision Expenditures *(in millions of dollars)*	Actual	Business Plan			
	2017	2018	2019	2020	2021
Nuclear Decommissioning and Nuclear Waste Management Expenditures					
Nuclear Operations*	276	330	342	347	342
Support Services	14	14	14	14	14
Total Nuclear Provision Expenditures	**290**	**344**	**355**	**361**	**356**
Nanticoke GS Decommissioning	12	13	21	40	-
Lambton GS Decommissioning	11	15	35	22	14
Other	-	0	-	12	7
Total Thermal Decommissioning Expenditures	**23**	**28**	**56**	**74**	**21**
Total Provision Expenditures	**313**	**373**	**411**	**435**	**377**

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

Capital Expenditures *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Sustaining					
Nuclear	357	384	353	289	244
Regulated Hydroelectric					
Sir Adam Beck Water Conveyance System Project	3	8	7	20	90
Other Projects	118	144	125	122	117
Total Regulated Hydroelectric	121	152	133	142	207
Contracted Generation Portfolio					
Little Long Dam Safety Project	-	6	34	149	98
Other Projects	37	45	30	14	8
Total Contracted Generation Portfolio	37	51	65	163	106
Support Services					
Information Technology Projects	84	60	35	50	26
Other Projects	16	24	20	29	13
Total Support Services	100	84	56	80	40
Total Sustaining Capital	**615**	**672**	**606**	**674**	**597**
Development Projects*					
Darlington Refurbishment Project***	1,249	1,231	1,127	947	1,129
Ranney Falls GS Redevelopment**	25	35	13	0	-
Sir Adam Beck Units 1 & 2 Conversion	1	9	41	37	36
Nanticoke Solar Project**	6	103	0	0	0
Calabogie GS Redevelopment**	2	3	3	61	18
Other Business Development	28	28	69	62	49
Total Development Projects	**1,311**	**1,410**	**1,253**	**1,107**	**1,233**
Total Capital Expenditures	**1,926**	**2,082**	**1,859**	**1,781**	**1,830**

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

Financing and Liquidity Outlook - Years Ended Dec 31	Actual	Business Plan			
(in millions of dollars)	2017	2018	2019	2020	2021
Opening Cash Balance	**186**	**234**	**273**	**354**	**249**
Net Operating Cash Inflows before the following:	**1,723**	**2,227**	**3,070**	**2,646**	**3,113**
Earnings from Fair Hydro Trust (pre-tax)	1	64	131	206	285
Interest Paid (excl. Fair Hydro Trust)	(251)	(261)	(264)	(250)	(230)
Nuclear Funds Contribution	-	-	-	-	-
Pension Fund Contribution	(212)	(215)	(219)	(213)	(217)
OPEB Payments	(110)	(112)	(116)	(121)	(125)
Internally Funded Nuclear Provision Expenditures	(208)	(235)	(219)	(202)	(184)
Net Cash from Operations	**944**	**1,468**	**2,384**	**2,067**	**2,642**
Investing Activities					
Sustaining Capital Expenditures	(615)	(672)	(606)	(674)	(597)
Darlington Refurbishment	(1,249)	(1,231)	(1,127)	(947)	(1,129)
Ranney Falls GS Redevelopment	(25)	(35)	(13)	(0)	-
Sir Adam Beck Units 1 & 2 Conversion	(1)	(9)	(41)	(37)	(36)
Nanticoke Solar	(6)	(103)	(0)	(0)	(0)
Other Development	(30)	(32)	(72)	(123)	(68)
Capital Expenditures	**(1,926)**	**(2,082)**	**(1,859)**	**(1,781)**	**(1,830)**
Pre-tax Proceeds from Sale of 700 University Ave. Property	484	-	-	-	-
Pre-tax Proceeds from Sale of Lakeview Site	-	267	-	-	-
Acquisition of Fair Hydro Trust Assets	(1,179)	(2,326)	(2,557)	(2,812)	(2,741)
Proceeds from Deposit Note (Peter Sutherland Sr. GS)	70	-	-	-	-
Other	73	16	-	-	-
Net Cash Outflow for Investing Activities	**(2,478)**	**(4,125)**	**(4,416)**	**(4,593)**	**(4,571)**
Financing Activities					
General Corporate Debt - *Debt Issuance/Refinancing*	1,301	1,191	128	365	200
- *Debt Retirement*	(900)	(395)	(365)	(660)	(185)
Private Placement Debt - *Debt Issuance/Refinancing*	-	-	-	-	-
- *Debt Retirement*	(203)	(3)	(3)	(3)	(228)
Fair Hydro Trust Senior Debt - *Debt Issuance*	601	1,184	1,302	1,432	1,397
Short-Term Notes - *Net Issuance (Repayment)*	260	200	(50)	75	(385)
Issuance of Class A Shares	519	1,022	1,123	1,235	1,206
Dividends Paid	-	(482)	-	-	-
Distribution Paid to Non-Controlling Interests	(15)	(22)	(22)	(23)	(25)
Capital Contribution from Non-Controlling Interest	19	-	-	-	-
Net Cash from Financing Activities	**1,582**	**2,695**	**2,113**	**2,422**	**1,980**
Net Cash Inflow (Outflow) for Period	**48**	**39**	**81**	**(105)**	**52**
Ending Cash Balance	***234***	***273***	***354***	***249***	***301***
Total OPG Debt	***5,978***	***6,971***	***6,681***	***6,458***	***5,860***
Fair Hydro Trust Senior Debt	***601***	***1,786***	***3,088***	***4,519***	***5,917***
Total Consolidated Debt	***6,579***	***8,757***	***9,768***	***10,978***	***11,777***

APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

Financial Plan

Nuclear	Actual	Business Plan			
(in millions of dollars)	2017	2018	2019	2020	2021
OM&A					
Base*	1,254	1,251	1,276	1,294	1,298
Outage Incremental	314	334	246	336	116
Project Portfolio	123	91	82	82	87
Pickering Extension Enabling Costs	18	59	82	81	54
Darlington Refurbishment Project	36	23	3	38	23
New Nuclear **	0	1	1	1	1
Total Nuclear OM&A	**1,746**	**1,759**	**1,690**	**1,831**	**1,578**
Capital					
Project Portfolio***	357	384	353	289	244
Darlington Refurbishment Project **	1,223	1,203	1,100	921	1,104
Total Nuclear Capital	**1,580**	**1,588**	**1,453**	**1,211**	**1,348**
Nuclear Waste Provision Expenditures	**276**	**331**	**342**	**348**	**343**
Fuel Expense (Pickering and Darlington)	**225**	**226**	**236**	**202**	**201**

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

			Pickering				Darlington			
Metric	NPI Max	Industry Best Quartile	Actual 2017	2018 Annual Target	2019 Annual Target	2020 Annual Target	Actual 2017	2018 Annual Target	2019 Annual Target	2020 Annual Target
All Injury Rate (#/200k hrs worked)[1]	N/A	0.64	0.06	0.22	0.19	0.19	0.40	0.22	0.19	0.19
Collective Radiation Exposure (person-rem/unit)	80.00	45.33	74.36	110.30	83.40	126.10	93.56	79.80	80.00	79.00
Unit Capability Factor (%)	92.0	89.41	80.00	74.6	80.5	69.2	85.17	86.0	87.8	79.3
Forced Loss Rate (%)	1.00	1.49	5.18	3.50	3.50	3.50	1.72	1.00	1.00	4.28
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	4	25	20	12	4	13	7	4	4
WANO NPI (Index)	N/A	96.9	76.7	75.5	76.7	75.5	82.0	91.3	91.7	88.1
Human Performance Error Rate (# per 200k ISAR and contractor hrs)	N/A	0.02	0.12	0.06	0.06	0.06	0.05	0.06	0.06	0.06
Total Generating Cost per MWh[2]	N/A	$38.77	66.01	73.17	64.93	76.08	49.93	51.66	53.91	50.13

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

Financial Plan

Renewable Generation	Actual	Business Plan			
(in millions of dollars)	2017	2018	2019	2020	2021
OM&A					
Regulated Hydroelectric	193	184	183	188	190
Contracted Generation	109	114	115	104	106
Other*	11	6	8	8	8
Total Base OM&A	**313**	**305**	**306**	**300**	**304**
Regulated Hydroelectric	42	71	77	73	90
Contracted Generation	14	18	12	15	10
Total Project OM&A	**56**	**89**	**89**	**89**	**99**
Regulated Hydroelectric	235	255	260	261	279
Contracted Generation	122	133	127	120	116
Other	11	6	8	8	8
Total Renewable Generation OM&A	**368**	**394**	**395**	**389**	**404**
Capital					
Little Long Dam Safety Project	-	6	34	149	98
Sir Adam Beck Water Conveyance System Project	3	8	7	20	90
Other Sustaining	155	185	156	136	125
Total Sustaining Capital	**158**	**199**	**197**	**305**	**313**
Nanticoke Solar	0	103	0	-	-
Ranney Falls GS Redevelopment	24	35	13	0	-
Sir Adam Beck Units 1 & 2 Conversion	0	9	41	37	36
Other Development	36	5	-	-	-
Total Development Capital	**61**	**152**	**54**	**38**	**36**
Total Renewable Generation Capital	**219**	**351**	**251**	**343**	**349**
Total Thermal Decommissioning Expenditures	**23**	**28**	**56**	**74**	**21**
Hydroelectric Gross Revenue Charge and Thermal Fuel Expense					
Regulated Hydroelectric (net of SBG losses)**	320	326	325	330	315
Contracted Generation Portfolio	54	54	52	55	56
Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense	**374**	**380**	**378**	**385**	**370**

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

Renewable Generation	Actual 2017	Business Plan 2018	2019	2020	2021
All Injury Rate* *(#/200k hrs worked)*	2.05	1.23	1.06	1.03	1.03
Environment *(#)*					
Category C Spills	3	8	8	8	8
Environmental Infractions	1	7	6	6	6
Capacity *(MW)*	9,928	9,925	9,999	9,851	9,911
Regulated Hydroelectric	6,426	6,412	6,437	6,443	6,502
Contracted Generation (Hydro, Thermal and Solar)	3,500	3,512	3,560	3,407	3,407
Wind	1.8	1.8	1.8	1.8	1.8
Hydroelectric Availability *(%)*	**86.5%**	**87.3%**	**87.4%**	**88.0%**	**85.6%**
Regulated Hydroelectric	88.3%	89.2%	89.7%	89.4%	84.7%
Contracted Generation	74.9%	75.1%	72.5%	78.7%	91.6%
Hydroelectric Equivalent Forced Outage Rate *(%)*	**3.1%**	**2.0%**	**1.8%**	**1.7%**	**1.7%**
Regulated Hydroelectric	3.0%	1.7%	1.7%	1.7%	1.7%
Contracted Generation	3.9%	3.8%	2.1%	1.5%	1.4%
Thermal Equivalent Forced Outage Rate (Operating) *(%)*	2.4%	5.1%	5.1%	5.1%	5.1%
Total Hydroelectric Generating Cost per MWh** *($/MWh)*	23.9	26.8	25.3	25.0	26.0

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

Key Enterprise Level Initiatives

Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

Key Business Unit Initiatives

Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

From:	Gadi Mayman
To:	Mike Manning; Ken Kandeepan; Ronald Kwan
Cc:	Christina Zhang; Gavin He
Subject:	FW: OPG White Paper - GAC deferral
Date:	Monday, February 27, 2017 2:15:50 PM
Attachments:	Global Adjustment Deferral_White Paper_OPG r1a.pdf ATT00001.htm Global Adjustment Deferral - White Paper - Terms to MOE Feb 21_2017.pdf ATT00002.htm

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I took a quick look through it, and they haven't, to my mind addressed the guaranteed vs. direct debt question that I raised, by maybe I missed it in my quick perusal.

Gadi

-----Original Message-----
From: Imbrogno, Serge (ENERGY) [mailto:Serge.Imbrogno@ontario.ca]
Sent: Monday, February 27, 2017 2:07 PM
To: Steve Orsini (MOF) <Steve.Orsini@ontario.ca>; Steven Davidson (MTCS) <Steven.Davidson@ontario.ca>; Helen Angus (MOHLTC) <Helen.Angus@ontario.ca>; Scott Thompson (CAB) <Scott.Thompson@ontario.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: William Bromm (CAB) <William.Bromm2@ontario.ca>; Keley Katona (ENERGY) <Keley.Katona@ontario.ca>
Subject: Fwd: OPG White Paper - GAC deferral

Latest from OPG.

Sent from my iPad

Begin forwarded message:

From: "LEE John -TREASURY" <john.s.lee@opg.com<mailto:john.s.lee@opg.com>>
To: "Imbrogno, Serge (ENERGY)" <Serge.Imbrogno@ontario.ca<mailto:Serge.Imbrogno@ontario.ca>>
Cc: "Nelms, Scott (ENERGY)" <Scott.Nelms@ontario.ca<mailto:Scott.Nelms@ontario.ca>>, "Katona, Keley (ENERGY)" <Keley.Katona@ontario.ca<mailto:Keley.Katona@ontario.ca>>, "HARTWICK Ken -FINANCE" <ken.hartwick@opg.com<mailto:ken.hartwick@opg.com>>, "KING Catriona -OFFCORPSEC" <catriona.king@opg.com<mailto:catriona.king@opg.com>>, "LYASH Jeffrey -PRESIDENT" <jeffrey.lyash@opg.com<mailto:jeffrey.lyash@opg.com>>
Subject: OPG White Paper - GAC deferral

Serge:

As requested, please find attached the OPG “White Paper” which reflects OPG view and understanding of the proposed Global Adjustment Smoothing Account and financing structure. I have also attached the “proposed terms and conditions” referenced in the white paper which was original sent to Energy on February 21st.

John

John Lee | Vice President Treasurer |
Ontario Power Generation | 700 University Avenue, H18 A6, Toronto, Ontario M5G 1X6 |
416.592.6392 | john.s.lee@opg.com<mailto:john.s.lee@opg.com>

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February 27, 2017

Mr. Serge Imbrogno
Deputy Minister,
Ministry of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Deputy:

Below is a summary of OPG's preliminary views on the implementation of the Province's proposed Global Adjustment Smoothing Account and financing structure. These views are contingent on the proposed terms and conditions that were sent to the Ministry of Energy on February 21, 2017.

Understanding that the finalization of the legal terms, the Trust indentures, financing structure and other detailed terms will take several months and will involve collaboration between legal counsel, input from capital markets, parties involved and other stakeholders, this letter is intended to provide the guideline and framework which could form the foundation of the plan.

Please do not hesitate to contact me if you have any questions regarding this summary.

Sincerely,

Mr. Ken Hartwick
Chief Financial Officer and Senior Vice President, Finance
Ontario Power Generation
W: 416-592-6985
C: 647-544-6985
ken.hartwick@ opg.com

cc. Jeff Lyash, President and CEO, OPG

Background:

The Province has indicated that it will take steps to reduce electricity bills in the near term. It has identified reductions in the Global Adjustment Charge (GAC) charged to electricity customers as a means to achieve its policy goals. The Province is proposing to temporarily reduce the amount of the GAC charged to electricity customers (primarily RPP-eligible customers). The exact quantum and duration of the program is still not known but based on discussions with the Province GAC charges of approximately $2-5B per year for the next 5-10 years would be deferred and collected over future periods commencing after the deferral period. A combination of senior debt and subordinated debt (mainly sourced by additional equity from the shareholder) would be issued to fund the amount deferred. The financing cost of the debt and other costs of running the program would form part of the amounts recovered from customers over the term of the program.

The Province has requested that OPG administer the GAC deferral, because of OPG's participation in the market, regulatory knowledge and the potential ability to consolidate the activity and accounting with OPG. Given the significant amount of financing required for the GAC deferral, OPG has developed a financing structure (depicted below) to:

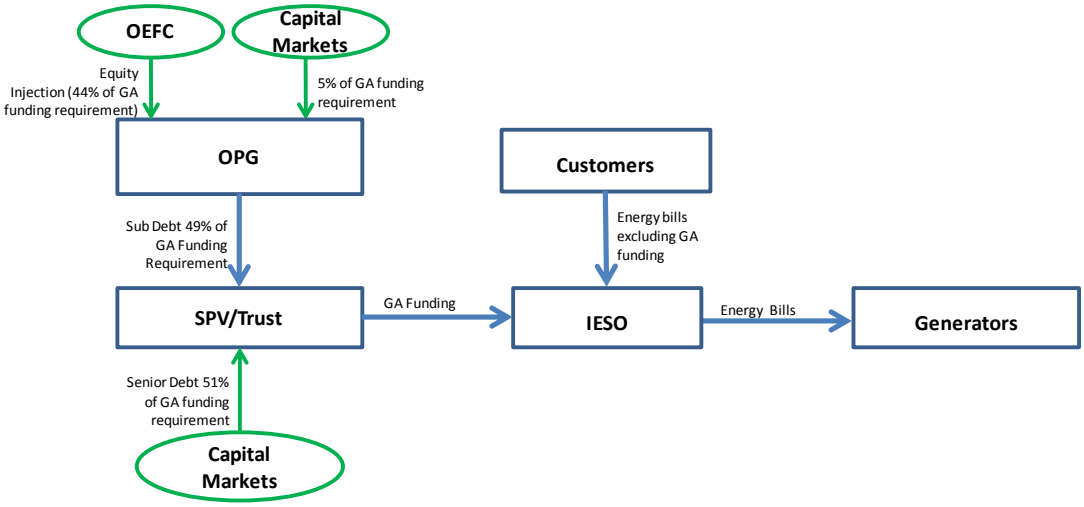
- restrict the risk to OPG;

- maximize the cost-effectiveness of the Trust or the Special Purpose Vehicle ("SPV") financing vehicle; and
- allow for consolidation into OPG financial statements.

The success of this structure is dependent on achieving a number of objectives which are reviewed in the following sections:

A. Ability to Recognize an Asset and Record Revenue
B. Ability to Consolidate the SPV into OPG
C. Ability to Finance
D. External Assessment
E. Risk Summary

All of the percentages shown in the graphic below are indicative and will be highly dependent on the legislation that the Province will enact:



Process:

The IESO will effectively sell the 'right to collect' deferred future revenue from ratepayers (GA Recovery Right asset) to the SPV in return for cash proceeds. In order for the SPV to purchase this asset the SPV will obtain the financing from two key sources: 51% directly from capital markets and 49% as subordinated debt from OPG. OPG will obtain 44% of this financing as an equity injection from the Province and 5% from capital markets.

A. Ability to Recognize an Asset and Record Revenue

Accounting Requirements under International Financial Reporting Standards (IFRS)

1) It is our understanding that the IESO and KPMG have concluded that the sale of this 'right to collect' future revenue (or regulatory asset) is not a financing transaction and will not be recorded as a financial liability. Based on that conclusion, the right to collect will be accounted for as an intangible asset in the SPV.

2) In order to the SPV to record this right as an intangible asset, the right must meet the following conditions:
   - The intangible asset must be separable and arise from a contractual or legal right (i.e. mandated by the Legislation and SPV Indenture Agreement).
   - The SPV must have the control and power to obtain future economic benefits from the intangible asset.
   - The SPV must be able to demonstrate that the intangible asset is purchased at fair value.

3) In order for the SPV to recognize appropriate revenue to offset any ongoing costs, the Legislation must require interest, carrying and administrative costs to be paid to the SPV on a monthly basis. This may result in additional amounts to be deferred to achieve the desired customer impact. Payment of revenue to the SPV is also important to service the interest expenses of the debt.

B. Ability to Consolidate the SPV into OPG under IFRS

OPG 'Control' of the SPV - Accounting Requirements

1) In order to meet the accounting definition of 'control', accounting guidance must be considered. There are no bright lines to determine whether OPG has exposure, or rights, to variable returns from its involvement with the SPV, or whether it has the ability to affect the returns of the SPV through its power over the SPV. Rather, all facts and circumstances are considered when assessing whether an entity has control over another entity. Based on the relevant accounting guidance under IFRS, OPG has proposed terms necessary to demonstrate that OPG has control over the SPV. OPG's external auditors, Ernst & Young, has provided their concurrence that based on the information provided to them to date that the following conditions should permit consolidation of the SPV by OPG.

Directive:

1. The SPV must be undertaken by OPG as a business initiative on its merits. A Shareholder Directive is to be limited to direct OPG to investigate the option of establishing a SPV vehicle to administer, finance and operate the Global Adjustment plan. The control, risk and rewards of that SPV will determine its consolidation into OPG as a business enterprise.

SPV:

2. The SPV should not operate in a predetermined way such that OPG does not have decision-making authority over the SPV's ongoing activities after its formation (i.e. should not operate on 'autopilot').
3. OPG must have the ability to appoint and remove the Trustee (or Board of Trustees), with no veto right by the Province. No party shall have the ability to remove OPG from its role and authority in the SPV.
4. The Province cannot have the right to veto OPG's decisions about the relevant activities of the SPV. OPG must have the power over the relevant activities of the SPV and be compensated. The relevant activities of the SPV include (but are not limited to) the evaluation and decisions on financing alternatives, duration, and the strategy to minimize financing costs. OPG must have the power to establish operating and capital budgets of the SPV.
5. OPG must have the power to determine or change operating and financing policies of the SPV, which will affect the variability of risks and returns.
6. The Province or its agencies must not directly or indirectly fund (through debt or equity) more than 50% of the following:
    - The SPV
    - Any of OPG's investments in the most subordinated debt of the Trust
7. OPG must own greater than 50% of the most subordinated debt and targeted to be no less than 5%[1] of the total debt of the SPV. Such ownership must be financed entirely by OPG through operating cash flows or external debt, without assistance from Provincial sources. A quantitative analysis should be performed at a later date to corroborate the appropriateness of the 5% threshold to support that the 5% subordinated debt investment is sufficient to absorb most of the expected variability in the SPV.
8. OPG must have the ability to earn variable returns by exercising its authority, which shall be accomplished as follows:

[1] While the rest of the letter refers to a 10% investment in the most junior subordinated debt with OPG owning 5%, it should be noted that OPG should own more than 50% of the most subordinate debt. For simplicity, the degree to which OPG's ownership beyond 50% is not shown in this letter.

a. The cash flow from the restructured asset shall include interest determined based on a relevant benchmark that is appropriate relative to the restructured asset, plus an appropriate margin consistent with the relevant market and other risks
b. OPG shall have the authority to determine the financing strategy, which will vary the financing costs with the objective of enabling the SPV to achieve a more favourable return compared to the return from the restructured asset
c. The SPV shall establish classes of liabilities (senior, subordinated and the most subordinated). The classes would allow the SPV to delineate financing of lower risk investment and investment that would bear higher residual risk. The delineation would limit OPG's self-funded investment to a reasonable level in order to allow OPG to remain a self-sustaining entity.
d. OPG shall, through its ownership of the most subordinated liability, be able to capture and retain the pricing difference between cost of financing and benchmark for interest on the restructured asset, or any residual risk of restructured asset. The targeted return of the subordinated liability should be reflective of the underlying risks and compensate holders for active management that would be required.
e. OPG should participate in the detailed design of the above and the SPV documentation to ensure that it has substantive power and variability, which will allow OPG's Board of Directors to evaluate the opportunity as a business initiative instead of through a shareholder directive.

Nothwithstanding the above, under certain Defined Forced Majeure for emergency events (e.g. unlikely credit market event or disruption where it is not possible to borrow from the market at a reasonable rate), the OEFC may provide bridge financing beyond the designated percentage for a defined period. The relevant terms should ensure that this temporary measure does not detract from the rights of OPG to direct all of the relevant activities of the SPV. Additionally, OPG should not be protected from risk of loss by the OEFC with respect to its subordinated investment, nor should it lose its right to derive the residual returns should such bridge financing be required.

Legislation

9. The Legislation must require interest, carrying and administrative costs to be paid to the SPV on a monthly basis, so that the SPV is able to recognize appropriate revenue to offset any ongoing costs.
10. The Legislation must dictate the manner in which the restructured asset would be determined, collected, and the period of collection, so that the determination of the restructured asset will not be subject to the Province's decisions on an ongoing basis, but determined based on a formula. Alternatively, the Legislation may allow for an adjustment to the pre-determined deferral formula based on specific parameters that would limit the adjustment to the restructured asset. Adjustments beyond the specific parameters would require approval by the Board of Trustees.
11. The Legislation must be written to avoid legal or constitutional challenges and be irrevocable to reduce the cost of borrowing and with a specific formula which determines the deferral amount. As irrevocability would be difficult under Canadian law one mitigation would be to provide a Provincial guarantee which only applies with cancellation or amendment of the legislation.
12. The spirit of the above terms should be reflected in the SPV Indenture Agreement as well as Legislation, wherever possible.

2) The Trust is expected to be financed as follows:
   - 51% senior secured debt from external markets
   - 39% senior subordinated debt from OPG (via Province equity injection into OPG)

- 10% junior subordinated debt from OPG (5% from external markets and 5% from Province equity injection into OPG).

When assessing control, an investor shall consider the nature of its relationship with other parties and whether those parties are acting on the investor's behalf (i.e. they are 'de facto agents'). If OPG is assessed to be a 'de facto agent' of the Province, it will compromise the ability for OPG to consolidate the Trust. The split above is to meet the following conditions to ensure that OPG is not considered a 'de facto agent' of the Province:

- The Province or its agencies must not directly or indirectly fund (through debt or equity) more than 50% of the following:
  - The Trust
  - Any of OPG's investments in the most subordinated debt of the Trust
- OPG must own greater than 50% of the most subordinated debt and targeted to own no less than 5% of the total debt of the Trust. Such ownership must be financed entirely by OPG through operating cash flows or external debt, without assistance from Provincial sources.

3) The Province will need to conclude on whether OPG still meets the definition of a Government Business Enterprise as defined under Public Sector Accounting Board standards in order to obtain the preferred consolidation treatment after the transaction. We also recommend that the Province to undertake the analysis deemed necessary to confirm the accounting treatment in its consolidated Public Accounts, including if the recognition of the intangible asset would result in an offsetting liability in the Public Accounts.

C. Ability to Finance

Property Right or Right to Collect
Legislative Requirements for Financing
The GA Recovery Right must be structured to encompass the following elements:

- Right to recover from and bill Ontario electricity customers for (1) the principal amount of GA that is being deferred, (2) all interest and other financing costs incurred in respect of the deferral of the GA, (3) all fees, expenses and other administrative costs associated with such financing;
- Repayment/amortization schedule as agreed by the IESO and any purchaser of such GA Recovery Right (or pursuant to a pre-defined schedule/formula that covers all of the purchaser's principal, interest and ongoing financing costs on a monthly basis);
- Repayment/amortization schedule must include a true up mechanism to ensure all costs associated with the deferral can be recovered from customers;
- IESO may dispose of the GA Recovery Right, provided that any such disposition shall be a true sale and absolute transfer to the purchaser of the IESO's right, title and interest in and to the GA Recovery Right;
- Purchaser will have the right to require the IESO (or any successor) to collect the principal amount of GA Recovery Right, together with interest, financing and administration costs, on the agreed repayment/amortization schedule;
- Right must be irrevocable and, if amended by future governments, debt holders have the right of action against the government to recover the amount outstanding including interest, fees, expenses and any damages resulting from the amendment;
- GA Recovery Right will not be subject to any set-off, counterclaim or other defence by the IESO or any successor or affiliated entity; and
- Make certain amendments to the Electricity Act to allow OPG to implement the SPV financing structure (e.g. allowing OPG to create subsidiaries and holding companies, and to have a beneficial interest in the SPV, etc). This would provide flexibility to accommodate possible variations to the financing structure that may be desirable over time.

Detailed legislative requirements are specified in the attachments as follows:

Attachment 1 Legislative requirements to allow deferral of global adjustment amounts to be financeable

Attachment 2 Statutory amendments

The proposed financing structure for the SPV is:

	Risk Profile	Source	% of Total Funding Requirements
Tranche A Senior Debt	The least risky	Capital Markets	51%
Tranche B Sub Debt	In between A&C	OPG via OEFC	39%
Tranche C Sub Debt)	The most risky	OPG via OEFC	5%
		OPG via Capital Markets	5%

SPV structure is used to accomplish the following:

- SPV holds right to charge customers for the benefit of debt holders;
- Allows the financing vehicle to be ring-fenced from OPG as an SPV structure is set up as generally single purpose entities with no other operations that could add risk to the SPV, dilute debt holder rights, allow parties from other operations to claim rights to the future recovery from customers or allow these other parties to initiate bankruptcy proceedings;
- Enables SPV to potentially get a higher credit rating than OPG;
- Supports consolidation with OPG provided accounting requirements are satisfied;

This approach supports a number of objectives of the GA Recovery Right:

- 51% external senior debt supports separation of the SPV from the Province
- 5% junior subordinated debt establishes OPG's "at risk" equity which supports separation of the SPV from the Province
- Subordinated debt provides flexibility to the financing structure and additional credit support to external debt holders
- Subordinated debt sourced from OPG (mainly funded by equity injection from the Province) minimizes impact on OPG credit metrics reducing risk of an OPG rating downgrade that could result in the SPV being consolidated directly with the Province as the SPV would be considered an arm of the Province.

Recent transactions used as precedents are:

<u>Duke Energy Florida Project Finance LLC</u>
June 2016
5 series of bonds totalling USD$1.3B
Weighted average life from 2 to 19 years with interest rates from 1.2% to 3.1%
Credit rating AAA

<u>Utility Debt Securitization Authority</u>
<u>Sponsored by Long Island Power Authority</u>
March 2016
Amount issued USD$0.6B
Weighted average life of 12 years and weighted average yield of 2.7%

August 2016
Amount issued USD$0.5B
Weighted average life of 7 years and weighted average yield of 2.0%

Credit rating AAA

Cumulative outstanding (including previous issuances): USD$4.2B

D. External Assessment

Shakerhill Partners, an external advisor, identified the following items in an assessment of the structure and financeability of the structure:

- The structure is financeable however there are a number of significant risks to the structure:
  - Canadian and Ontario law does not provide the same protection to property right as exists in the US federal and state constitutions to limit the ability of governments to adversely impair contracts to the detriment of the holder;
  - Legislation could mitigate some of the risks – deferred recovery asset to be "uncapped", regular semi-annual true up to ensure recovery, Province provides sufficient committed liquidity to the IESO so that temporary shortfall in recovery does not affect payments to SPV, term of the deferral recovery substantially exceeds the longest maturity of debt of the SPV and that true-up mechanism take account of potential for currency, interest rate and duration mis-match between the debt of the SPV and the recovery mechanism;
  - Size of the program may be too large for Canadian securitization market requiring access to the US securitization market;
- Final maturity of debt should not exceed 30 years from inception of the program
- True up mechanism should be designed such that the forecast of recovery is less than 10% of the customer bill under downside scenarios to limit growth of the deferral balance as a higher portion of the customer bill increases the political risk to debt holders which could result in a lower credit rating and potential impact on financeability
- Securitized debt products are specialized and price at a premium to other fixed rate instruments however a successful program supported by a strong credit rating this premium could shrink over time to a minor spread over Provincial debt
- OPG's credit rating should be maintained provided sufficient equity is injected to maintain credit metrics
- While the structure is not expected to impact the Province there are risks that the program could negatively impact the rating agencies view of the Province's financial management.

E. Risk Summary

i. Consolidation

- Elements of the proposed structure were established to support consolidation of the SPV into OPG. These items may not be sufficient to establish OPG as risk owner of the SPV and the SPV may need to be consolidated directly with the Province.

ii. Financeability

- The legislation establishing the structure and the property right for recovering the financing and associated costs may not be adequate for financing purposes resulting in more expensive financing or an inability to obtain the required external financing.

iii. Cost of Financing

- Future governments may enact legislation that changes the right of the SPV to recover amounts from customers.
- The right to recover amounts from future customers must be irrevocable and subject to full recovery from the government in the event that future governments reduce or eliminate the recovery. A legal structure that is weaker than the precedent US transactions increases the risk to debt holders and the cost of financing.
- Interest rates on bonds in the securitization market are higher than equivalent rated bonds. Rate for a AAA securitization credit is about 50 bps higher than GOC (rated AAA) for a 5 year term. This difference is attributable to the specialized structure of the bond, smaller investor pool for this bond, smaller size of the market and higher perceived risks of the bond.
- Any regulator involvement must not be seen to modify any terms of debt issued or the property right securing the debt as this would increase risk to debt holders.

- It may not be possible to issue debt to match the terms of the deferred asset so shorter term debt would be used which raises risk to re-finance the maturing debt as the market may no longer be interested in this product. As well, underlying reference interest rates may be higher and the market may require a higher spread to invest in this product.
- With the GA Recovery Right program continuing for 10 years, debt issued over this period is subject to changes in both the underlying reference interest rates and appetite of the market for this product.

iv. OPG Credit Rating

- Minimizing the impact of significant additional debt on OPG's credit rating is dependent on higher EBITDA arising from earned income on the GA Recovery Right in excess of external debt. Ability of the SPV to record revenue reflecting the growth in asset value.
- Potential OPG credit rating downgrade if legislative structure is not adequate to support long term recoverability, inability to record revenue from growth in asset value or agencies view equity injection as debt.
- OPG credit rating downgrade could result in loss of GBE status or result in SPV being consolidated directly with the Province.

Attachment 1

LEGISLATIVE REQUIREMENTS TO ALLOW DEFERRAL OF GLOBAL ADJUSTMENT AMOUNTS TO BE FINANCEABLE

The IESO currently has a right to collect GA monthly from ratepayers through provisions in the *Electricity Act, 1998*. It is proposed that collection of a certain portion of the monthly GA be deferred for collection in the future, and that the right to recover the deferred GA from ratepayers be used as a basis for structured financing/securitization.

The current proposal is for a trust to be created as a financing vehicle (the "**Trust**") in connection the deferred GA. The Trust will finance the deferral of the GA by purchasing the right to recover such deferred GA from the IESO for the principal amount of the GA being deferred. For example, if the amount of GA that is being deferred is $200 million in a given month, the Trust will purchase from the IESO the right to future recovery of the deferred GA and the associated financing costs (including interest and transaction costs) for $200 million in cash.

The Trust is expected to finance these purchases from the IESO through a combination of senior secured financing raised in the capital markets and subordinated financing from OPG (the funding for which will mostly be from equity injections from the OEFC/Province).

For accounting purposes, OPG will need to have the ability to direct the activities of the Trust, through a services agreement and/or through the Trust's constating document.

Based on securitized financing raised by utilities in the US (backed by utility cost recovery orders) and the current regulatory framework in Ontario, the legislation in Ontario would need to be amended to provide the following, at a minimum:

1. The IESO will be empowered to create an asset (the "**Regulatory Asset**") consisting of all right, title and interest in and to:

   (a) right to recover from and bill Ontario electricity ratepayers for:

   (i) the principal amount of GA that is being deferred for collection;
   (ii) all interest and other financing costs incurred in respect of the deferral of the GA (whether through senior debt raised in the public markets or subordinated debt raised from OPG or others); and
   (iii) (subject to the comments in paragraph 5 below in respect of OPG's internal administrative costs only) all fees, expenses and other administrative costs associated with such financing, including up-front and ongoing financing costs and any indemnity payments;

all on such repayment/amortization schedule as agreed by the IESO and any purchaser of such right (or pursuant to a pre-defined schedule/formula in the legislation that covers all of the purchaser's principal, interest and ongoing financing costs on a monthly basis); and

(b) all revenues, collections, claims, rights to payments, money or proceeds arising from the rights and interests set out in paragraph (a) above, regardless of whether such revenues, collections, claims, rights to payments, money or proceeds are imposed, billed, received, collected or maintained together with or commingled with other revenues, collections, rights to payments, payments, money or proceeds.

2. The IESO may dispose of the Regulatory Assets created from time to time on such terms as the IESO determines in accordance with the terms of directives to be issued to the IESO from time to time by the Minister, provided that any such disposition shall be a true sale and absolute transfer of the IESO's right, title and interest in and to a Regulatory Asset to the purchaser of the Regulatory Asset.

3. The Regulatory Assets will not be subject to any set-off, counterclaim or other defence by the IESO or any successor or affiliated entity thereof.

4. The legislation will need to recognize the Regulatory Assets as amounts that may be recovered by the IESO (e.g. it could be designated as a "GA Deferral" and would be included in the amounts collectible by the IESO through the GA collection mechanism, and would include interest and financing costs).

5. The purchaser of the Regulatory Asset will have the right to require the IESO (or any successor) to collect the principal amount of GA deferred, together with interest, financing and administration costs, on the agreed repayment/amortization schedule. **[NTD: In the LIPA securitization rate order, if the entity that is authorized to collect rates to service the bonds ends up defaulting, there is the ability to request a court to order "sequestration" and payments of amounts owing to the owner of the Regulatory Asset. Consider whether to include a similar right here. Alternatively, consider whether a security interest over the moneys collected by the IESO could be provided to the purchaser.]**

OEB would be provided with oversight over the internal administrative costs collected by the Financing Trust. This could be accomplished by (a) providing the purchaser of the Regulatory Asset with the right to require

the IESO or a successor to collect only the principal amount of GA together with interest and financing costs and third party fees and expenses, and (b) requiring the IESO to collect amounts through the global adjustment and make payments to the purchaser of the Regulatory Asset with respect to the internal administrative costs incurred by the purchaser in connection with the purchase and management of the Regulatory Asset and the Financing Trust, in accordance with the order of the OEB then in effect. Under this mechanism, the OEB would be required to review the purchaser's internal administrative costs through a streamlined process and issue such orders in accordance with rules to be prescribed under a new regulation under the OEB Act, which would clearly limit the OEB's scope of review and could establish the basis for the purchaser to receive an appropriate fee for its services.

6. In the event that any action is taken or permitted by the Province or any regulatory authority that limits, alters, or impairs the value of a Regulatory Asset or reduces the ability of the IESO or the purchaser of the Regulatory Asset to collect or recover the costs associated therewith, the owner of the Regulatory Asset and the holders of any bonds or other securities issued to finance the purchase of the Regulatory Asset, will have a right of action against the Province for any damages suffered as a result of such amendment.

Attachment 2

STATUTORY AMENDMENTS

The following is preliminary and is based on our current understanding of the proposed structure and objectives. For example, we have assumed that the structure will not entail the insertion of a new Holdco between OPG and the Province. As these aspects are refined, some of the suggested amendments described below may not be needed and other aspects that we are not aware of may need to be considered. Accordingly, these suggested amendments are provided for discussion purposes and are subject to change. We would welcome the opportunity to work with OPG and the Ministry on refining the scope and substance of required legislative and regulatory amendments.

A. Amendments to Implement Structure

Certain *Electricity Act, 1998* amendments would be needed to implement the anticipated structure (which we understand, as noted above, would not include a Holdco), as follows:

- **Section 53.1(1):** Amend to permit owning and operating generation facilities through subsidiaries (not only directly through OPG). In addition, amend to permit OPG to administer, manage, loan moneys to and have a beneficial interest in, if applicable, Financing Trust.

- **Section 53.2:** Amend to permit the Minister to acquire, hold, dispose of or otherwise deal with securities or debt obligations of, or any other interest in, OPG or any subsidiaries. This is to accommodate possible variations to the financing structure that may be desirable over time.

- **Section 53.■ (new):** New statutory section to permit the Minister to enter into arrangements relating to an exercise of powers under 53.2.

- **Section 53.■ (new)**: New statutory section providing that creditors of Financing Trust have no recourse to the assets of OPG or any of its subsidiaries (other than Financing Trust, if applicable). In addition, consideration should be given as to whether the Act should be amended so that the Financing Trust cannot be wound up or liquidated.

B. Miscellaneous Corporate Items to Address

- **OPG Articles:** Amend the OPG's articles to remove the private company restrictions.

- **MOA with Province:** Consider whether any amendments to OPG's MOA with the Province are required to contemplate the Financing Trust.

C. Amendments Under Electricity Act to Implement GA Smoothing

Based on our understanding that the global adjustment smoothing mechanism is intended to benefit residential and small business customers only and that the Minister will be responsible for determining how much global adjustment smoothing is to be applied in a given month, if any, amendments to the *Electricity Act*, *1998* and Ontario Regulation 429/04 (Adjustments Under Section 25.33 of the Act) would be needed to implement the mechanism, as follows:

(i) Electricity Act:

- **Section ■ (New):** Establish a new power for the Minister to make directives to the IESO in relation to the global adjustment smoothing mechanism and, particularly, for purposes of establishing global adjustment smoothing amounts from time to time (expected to be monthly). To the extent possible, the directive power should be drafted so as to limit the ability for a future Minister to require the IESO to do anything that would materially and adversely affect the Financing Trust or its lenders. **[NTD: While our understanding is that the Minister would direct this, we note from other materials we have seen that OPG may instead be recommending a formula approach. It is not clear what the formula would look like, where it would be set out or how it would be applied and by whom]**

- **Paragraph 25.33(1):** This section says that IESO shall make adjustments in accordance with the regulations to ensure that, over time, payments by prescribed classes of market participants reflect amounts paid to OPG, OEFC and distributors, as well as amounts paid to entities with whom IESO has a procurement contract. Add new subsection (c) so as to require IESO to ensure that, over time, payments by prescribed classes of market participants also reflect amounts paid to Financing Trust. **[NTD: Not certain this is needed if only to benefit residential and small business consumers, who are not market participants. May be needed in reference to payments from distributors and retailers]**

- **Paragraph 25.33(2):** This section says that distributors and retailers shall make adjustments in accordance with the regulations to ensure that, over time, payments by prescribed classes of consumers reflect amounts paid to OPG, OEFC and distributors, as well as amounts paid to entities with whom IESO has a procurement contract. Add new subsection (c) so as to require distributors and retailers to ensure that, over time, payments by prescribed classes of consumers also reflect amounts paid to Financing Trust.

- **Note**: As described below, the regulation will need to include new requirements for the IESO to record the global adjustment smoothing amounts in one or more variance accounts and to use those amounts to offset amounts otherwise recorded in the variance accounts under Section 25.33(3) of the Act. For context, we note:

    - Section 25.33(3) says that adjustments under (1) or (2) relating to electricity consumed by consumers whose rates are determined by

the OEB under s. 79.16 of the OEB Act (i.e. RPP Customers) shall instead be made in accordance with the regulations to one or more variance accounts established and maintained by the IESO.

- Section 25.33(4) says IESO, distributors and retailers shall make and receive such payments, set-offs and credits as may be required or permitted by the regulations with respect to consumers described in (3), i.e. RPP Customers.

- Section 25.33(5) says that IESO shall establish and maintain such variance accounts as may be needed to record all amounts payable or receivable by it under 25.33.

(ii) O. Reg. 429/04 (Adjustments Under Section 25.33 of the Act):

- **Section 1(1):** Consider adding definitions for "Financing Trust" and "global adjustment smoothing amount" or such other terms as may be preferred.

- **Section 1.2(1) (New):** Add section providing that, for the purposes of this Regulation, the global adjustment smoothing amount for a month is the amount determined by the IESO in accordance with a directive from the Minister under section ■ of the Electricity Act in respect of the month. **[NTD: See above note re use of Minister directives]**

- **Section 1.2(2) (New):** Consider adding a section providing that the IESO shall publish the global adjustment smoothing amount for a month by no later than the 10th business day of the following month [to align with general publication requirements for global adjustment under s. 1.1(2)].

- **Section 10(1):** Amend formula for calculating Class B GA rate by subtracting the global adjustment smoothing amount for a month from "M", which is the total amount of the global adjustment for the month. The global adjustment smoothing amount could be designated as "X", such that the formula would be (M-X-N)/(P-Q). Define "X" as the global adjustment smoothing amount for the month as determined by the IESO in accordance with the Minister's directive under section ■ of the Electricity Act for the month. **[NTD: See above note re use of Minister directives]**

- **Section 10.1 (New):** Add new section to deal with adjustments under subsection 25.33(3) of the Act, i.e. in respect of RPP consumers. This section should require the IESO to establish, within the variance account(s) it maintains pursuant to subsection 25.33(3) of the Act, one or more subaccounts in which it shall record the global adjustment smoothing amounts applicable to the classes of consumers described in subsection 25.33(3) of the Act. This section must also specify that the IESO shall apply the amounts recorded in the subaccounts against the balances in the variance accounts for purposes of section 79.16(3) of the OEB Act.

  - **Note:** This is a key aspect because, when the OEB determines RPP rates, it must take into account the balances in the variance accounts established by the IESO under s. 25.33 of the Electricity Act and make adjustments with a view to eliminating the balances within 12 months. This proposed new section 10.1 causes the IESO to reduce (in the near term) the variance account balances by the global adjustment smoothing amounts, as provided by Financing Trust, thereby enabling the OEB to determine RPP rates that, despite being lower for RPP consumers in the near term, still eliminate the relevant variance account balances within 12 months.

- **Paragraph 11(2)2.ii:** Amend the formula for calculating the allocation of global adjustment for a month to a licensed distributor that is a market participant by subtracting the global adjustment smoothing amount for a month from "M", which has the same meaning as under section 10(1). The global adjustment smoothing amount could be designated as "X", such that the formula would be [(M-X-N) x (R+S-T)]/(P-Q). Define "X" as suggested under section 10(1).

- **Paragraph 11(2)3:** Amend the formula for calculating the allocation of global adjustment for a month to each Class B market participant by subtracting the global adjustment smoothing amount for a month from "M", which has the same meaning as under section 10(1). The global adjustment smoothing amount could be designated as "X", such that the formula would be [(M-X-N) x U]/(P-Q). Define "X" as suggested under section 10(1).

- **Paragraph 16(7)4:** Consider amending the description of "Global Adjustment" that is required to be included on certain invoices so as to inform consumers that their portion of the global adjustment for the month (i) may have been reduced by the application of a global adjustment smoothing amount from the Financing Trust, or (ii) may include amounts payable to the Financing Trust in respect of global adjustment smoothing amounts previously applied.

- **Section 20(1):** This section establishes an obligation for the Ontario Electricity Financial Corporation and every licensed distributor that is a market participant to give the IESO such information as the IESO may require for the purposes of the Regulation in the form specified by the IESO and before the expiry of the period specified by the IESO. Consider amending to extend this obligation to the Financing Trust.

- **Section 20(6):** This section provides that on request by the OEB, the IESO, a licensed distributor, an embedded generator, a retailer or the OEFC shall give the OEB such information relating to this Regulation as the OEB may require, in the form and within the period specified by the OEB. Consider amending to extend this obligation to the Financing Trust.

D. Amendments Under OEB Act to Implement Cost Recovery for Financing Trust

Amendments to the *Ontario Energy Board Act*, including amendments to O. Reg. 95/05 (Classes of Consumers and Determination of Rates) and the introduction of a new regulation, would be needed to implement a cost recovery process for the Financing Trust in relation to the global adjustment smoothing mechanism, potentially with limited OEB oversight, as follows:

(i) Ontario Energy Board Act:

- **Section 78(3.3):** This provision establishes an obligation for the OEB, when determining rates for the retailing of electricity, to take into account balances in variance accounts established under section 25.33 of the Electricity Act and to make adjustments "with a view to eliminating those balances within 12 months or such shorter time periods as the Minister may direct." Consider whether any amendments are needed, and confirm this works with the framework being proposed.

- **Section 78.7 (New):** We understand that the Province may want the OEB to have an oversight role. One possible approach would be to establish a new statutory section establishing that the IESO shall make payments to the Financing Trust with respect to the internal administrative costs incurred by the Financing Trust in connection with the purchase and management of the Regulatory Asset and the Financing Trust. Such payments by the IESO would need to be made in accordance with the order of the OEB then in effect, which orders shall be made by the OEB in accordance with rules prescribed under a new regulation.

    - The new regulation would need to be clear that the OEB does not have jurisdiction to consider the principal amount or any interest, financing costs, third party fees or expenses. Rather, OEB's role would be limited to considering the internal administrative costs of the Financing Trust and ensuring the Financing Trust receives an appropriate fee for its services, all of which would be recovered by the Financing Trust from the IESO, which would collect those amounts in the global adjustment. Note that, if this approach is accepted, the IESO and distributors and retailers would need the authority to collect such amounts as part of the GA and IESO would need the authority to pay such amounts to the Financing Trust. As such, additional amendments would be needed under O. Reg. 429/04.

- **Note:** Section 79.16 of the OEB Act does not require changes, but the significance of this provision should be understood.

    - Section 79.16 gives the OEB responsibility for determining electricity commodity prices for eligible consumers. Eligibility is determined under Reg. 95/05 (Classes of Consumers and Determination of Rates), which is also known as the Regulated Price Plan (RPP) Regulation.
    - Section 4(2) of the RPP Regulation defines RPP-eligible consumers as low volume consumers (i.e. those who annually use less than 150,000 kWh

or such other amount as prescribed), consumers with demand of 50 kW or less, residential consumers that have accounts with distributors, consumers who annually use 150,000 to 250,000 kW of electricity, and consumers who have accounts with distributors if in the farming business.

- Paragraph 6(1)3 of the RPP Regulation provides that "In determining the rates (for RPP-eligible consumers), the Board shall forecast the cost of electricity to be consumed by the consumers to whom the rates apply, taking into consideration adjustments required under section 25.33 of the *Electricity Act, 1998* and shall ensure that the rates reflect those costs."
- The Ontario Energy Board has developed a Regulated Price Plan Manual (revised February 16, 2016) to describe the processes and methodologies it uses for determining electricity commodity prices that are charged to RPP consumers pursuant to Section 79.16 of the OEB Act and paragraph 6(1)3 of the RPP Regulation.

(ii) O. Reg. 95/05 (Classes of Consumers and Determination of Rates)

- **Paragraph 6(1)3:** Amend so as to require the Board, when forecasting the cost of electricity to be consumed by the consumers to whom the rates apply, to take into consideration not only the adjustments required under section 25.33 of the Electricity Act but also the application or prior application of global adjustment smoothing amounts determined by the IESO in accordance with Minister directives under section ■ of the Electricity Act, and to ensure that the RPP rates reflect those amounts. **[NTD: See above note re use of Minister directives]**

(iii) New Regulation (Payments to the Financing Trust)

- If the OEB is to be given the role of reviewing and approving the recovery of OPG's internal administrative costs for the Financing Trust under the potential section 78.7 (see above), then this regulation should describe the process and criteria pursuant through which the OEB would determine the amounts that the IESO would be required to collect through the global adjustment, in accordance with section 25.33 of the Electricity Act, and pay to the Financing Trust in respect of the provision of global adjustment smoothing amounts. This part of the regulation should establish:

    - any reporting requirements from the Financing Trust and/or the IESO to the OEB in connection with the global adjustment smoothing mechanism;
    - the frequency of the OEB making determinations under this part of the regulation;
    - the process through which the OEB shall make these determinations, which should be a streamlined administrative process rather than a public hearing process or, if a hearing is needed, then the scope of the proceeding should be clearly and narrowly constrained so as to deter intervenor involvement, lengthy proceedings and reduce/eliminate risk to recovery by Financing Trust;

- the basis for the OEB's determinations as to the payments that shall be made to the Financing Trust, which should specify that:
  - the Financing Trust shall recover its prudently incurred internal administrative costs on a forecast basis each year;
  - the Financing Trust shall receive an appropriate fee each year (with some guidance as to what would be appropriate); and
  - the approved payment amounts shall be collected by the IESO through the global adjustment and paid to the Financing Trust in accordance with the order of the OEB then in effect. Note that O. Reg. 429/04 would likely need amendments to permit IESO (and distributors and retailers) to collect these amounts through the global adjustment.

GA Smoothing – OPG Accounting Considerations

- An SPV/Trust is a stand-alone entity able to conduct business separately under a Trust agreement

The conditions required for OPG to consolidate the SPV/Trust are outlined in the following table

Issue	Response
1. Decision Making	• OPG must have decision making authority on the operation of the SPV/Trust (without a veto right by the Province), including naming of trustees, establishing operating plans and budgets, setting or changing financing policies. • The SPV/Trust while operating within the legislation, must be controlled by OPG to operate freely and to alter terms and conditions not specified in the legislation to ensure recovery of the deferred amounts
2. Business Risk	• The SPV/Trust must have variability of returns as a normal business enterprise would, including such things as interest charged on deferred amounts, decisions on how to finance these deferred amounts, the ability to make / lose and keep any spread from financing
3. Funding	• The Province cannot directly or indirectly fund more than 50% of SPV/Trust or any investment in the SPV/Trust • OPG must own at least 50% of the most exposed equity /sub-debt in the SPV/Trust
4. Directive	• Directive that is issued should not be prescriptive or direct OPG to set up this business. The directive should only be “guiding” i.e. to allow OPG to evaluate options and put forward to the OPG Board a recommended plan for Shareholder approval

GA Smoothing – OPG Accounting Considerations - continued

Issue	Response
5. Other required Attributes:	The legislation that supports the formation of the SPV/Trust must have the following attributes: • Must require interest, carrying and administrative costs be paid to the Trust to allow for Revenue recognition • The amount to be deferred must either be specified or be calculated based on a specific formula that is not subject to ongoing decision making by the Province. **The Province cannot have the ability to override this formula** • Legislation should be written to avoid the possibility of being revoked with wording to ensure the SPV/Trust and its debt holders would have their capital guaranteed and paid for directly by the Province if such a situation were to happen • The spirit of the legislation should be reflected in the Trust Indenture Agreement

GA Financing Structure Requirements

KEY ELEMENTS REQUIRED TO ENSURE THE DEFERRAL OF GA CHARGES CAN BE FINANCED:

Creation of Strong Property Rights

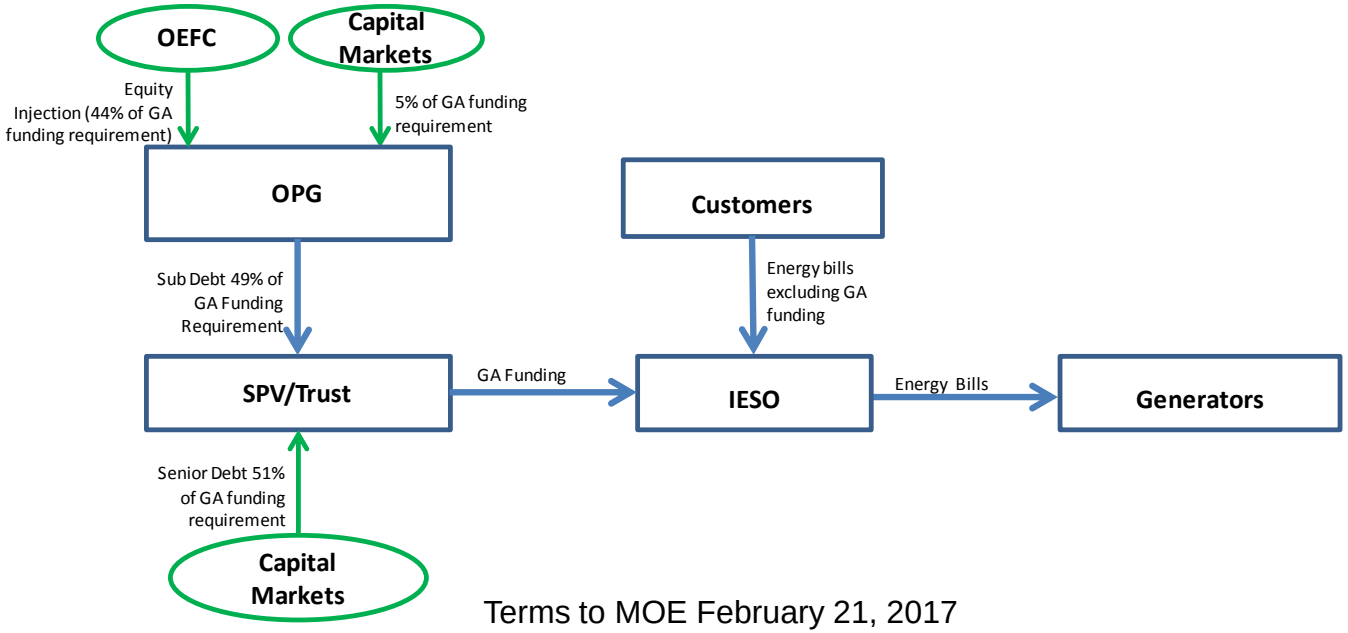
- Legislation enshrines the ability of the IESO to create a Right to charge customers in the future for the Global Adjustment (GA) deferred today including principal amount deferred, interest and other financing costs on the amount deferred and fees, expenses and other administrative costs.
- The Right can be sold to an appropriate Trust or Special Purpose Vehicle (SPV) to obtain funds to pay amounts due to generators under contracts or regulation. These SPVs are generally single purpose entities with no other operations that could add risk to the entity, dilute debt holder rights, allow parties from other operations to claim rights to the future recovery from customers or allow these other parties to initiate bankruptcy proceedings.
- Right must be irrevocable and if the Right is amended by future governments the debt holders have the right of action against the government to recover the amount outstanding including interest, fees, expenses and any damages resulting from the amendment.
- Right must specify the recovery period or the mechanism for setting the recovery rate including true up of the rate to ensure all amounts are recovered

Economic Factors

- Limits on the recovery amount (principal, interest, fees and expenses) charged to customers in future periods must have compensating elements such as longer recovery period to ensure the full amount deferred plus interest, financing and other administration costs is recovered from customers.
- Need to balance customer relief with debt holder risk. Longer recovery periods and larger deferred balances increase risk to the debt holder of future government intervention.
- The amount required by the SPV to purchase and service the Right will be funded 51% from debt holders, 5% from OPG through capital markets and 44% from OPG via equity injection to OPG from the Province. The funding from OPG will be loaned to the SPV as subordinated debt.

GA Financing Structure Requirements - continued

- SPV will be used to raise the GA financing and ring fence OPG from its legal obligations
- SPV will be structured to allow for GBE accounting consolidation into OPG
- Given that SPV will be consolidated into OPG for accounting purposes, the significant amount of debt required to fund the GA deferral will have a severe impact on OPG's credit rating. If 100% of the requirement is funded by debt OPG would be downgraded.
- To manage this exposure and minimize the cost of funding. The required funding would be split into 2 buckets:
    1. 56% from capital markets, and
    2. The remainder provided by the Province via equity injection, which would be loaned to SPV as subordinated debt.
- The use of equity to fund a portion of the GA deferral also allows for an improvement in both Net Income and EBITDA as incremental revenue is captured by the increase in the value of the deferral which would offset the fiscal impact of the borrowing at Province level.
- Credit rating metrics are generally maintained within established limits.



From:	Gadi Mayman
To:	Ronald Kwan; Ken Kandeepan; Mike Manning
Cc:	Anna Strathy; Gavin He
Subject:	Fw: GA Financing Response to Minister"s Request
Date:	Tuesday, April 18, 2017 9:36:09 AM
Attachments:	GA Financing Response to Minister"s request.pdf

The OFA isn't mentioned in the body of the letter, but given that I'm cc'd with a pretty esteemed list, I'll take that as sufficient.

From: LORD Bernard -BOARDCHAIR <bernard.lord@opg.com>
Sent: Tuesday, April 18, 2017 9:10 AM
To: 'glenn.thibeault@ontario.ca'
Cc: Charles Sousa (MOF); Scott Thompson (CAB); Serge Imbrogno (ENERGY); Gadi Mayman; LYASH Jeffrey -PRESIDENT; HARTWICK Ken -FINANCE; GINTHER Chris -CAO; KING Catriona -OFFCORPSEC; MATHIAS Carlton -OFFCORPSEC
Subject: GA Financing Response to Minister's Request

Hello,

Please see the attached letter from Bernard Lord, Board Chair Ontario Power Generation.

Thanks,

Rosemarie

Rosemarie Hoilett
Executive Assistant - Jeff Lyash President & CEO | Bernard Lord Board Chair
Ontario Power Generation
700 University Ave | H19-A24
Toronto ON M5G 1X6
416-592-2114 | rosemarie.hoilett@opg.com

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ONTARIO POWER GENERATION

Bernard Lord
Board Chair

700 University Ave, Toronto, ON M5G 1X6

Tel: 416-592-2115
bernard.lord@opg.com

April 18, 2017

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Thibeault,

I am writing in response to your letter dated April 13, 2017, in which you requested OPG work with the Ministry of Energy, the IESO and the OEB and their respective advisors to consider and propose a financing plan to refinance the Global Adjustment in a manner that achieves the Province's price objectives, as outlined in the Premier's March 2, 2017 announcement.

As requested, OPG is working with the Ministry of Energy, the IESO and the OEB and their respective advisors to develop a plan that will incorporate the matters you identified, including potential structures and mechanisms that permit viable financing, sources of financing and required changes to legislation, regulations and OPG's constating documents to facilitate the implementation of the financing plan in a commercial manner. The plan will also include assurances that implementation of the financing plan will have no adverse impacts on OPG, its operating assets or the manner in which they are regulated. I note the Province's commitment to provide OPG with the necessary assurances with respect to recovery of the principal, interest, and operating and other costs of any financing. This will be an important consideration for the OPG Board.

OPG has engaged financial and legal advisors with significant capital markets expertise, including experience in the United States where a number of state-owned utilities have put in place highly rated financing for costs that are to be recovered over a long period of time. Work on OPG's financing plan is being guided by these advisors and precedents.

The Board will provide you with our recommendation and plan in the timeframe requested.

Sincerely,

Bernard Lord
Board Chair

cc: The Honourable Charles Sousa, Minister of Finance
Scott Thompson, Deputy Minister of Finance
Serge Imbrogno, Deputy Minister of Energy
Gadi Mayman, CEO, Ontario Financing Authority
Jeff Lyash, President and CEO, Ontario Power Generation

From:	Gadi Mayman
To:	Scott Nelms (ENERGY)
Cc:	Ronald Kwan
Subject:	Fw: GA Financing Response to Minister"s Request
Date:	Tuesday, April 18, 2017 10:56:51 AM
Attachments:	GA Financing Response to Minister"s request.pdf

Hi Scott, do you have a copy of the final version of Energy's letter to OPG?

Thanks,

Gadi

From: LORD Bernard -BOARDCHAIR <bernard.lord@opg.com>
Sent: Tuesday, April 18, 2017 9:10 AM
To: 'glenn.thibeault@ontario.ca'
Cc: Charles Sousa (MOF); Scott Thompson (CAB); Serge Imbrogno (ENERGY); Gadi Mayman; LYASH Jeffrey -PRESIDENT; HARTWICK Ken -FINANCE; GINTHER Chris -CAO; KING Catriona -OFFCORPSEC; MATHIAS Carlton -OFFCORPSEC
Subject: GA Financing Response to Minister's Request

Hello,

Please see the attached letter from Bernard Lord, Board Chair Ontario Power Generation.

Thanks,

Rosemarie

Rosemarie Hoilett
Executive Assistant - Jeff Lyash President & CEO | Bernard Lord Board Chair
Ontario Power Generation
700 University Ave | H19-A24
Toronto ON M5G 1X6
416-592-2114 | rosemarie.hoilett@opg.com

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by return e-mail and delete this message from your system. Ontario Power Generation Inc.

ONTARIO POWER GENERATION

Bernard Lord
Board Chair

700 University Ave, Toronto, ON M5G 1X6

Tel: 416-592-2115
bernard.lord@opg.com

April 18, 2017

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Thibeault,

I am writing in response to your letter dated April 13, 2017, in which you requested OPG work with the Ministry of Energy, the IESO and the OEB and their respective advisors to consider and propose a financing plan to refinance the Global Adjustment in a manner that achieves the Province's price objectives, as outlined in the Premier's March 2, 2017 announcement.

As requested, OPG is working with the Ministry of Energy, the IESO and the OEB and their respective advisors to develop a plan that will incorporate the matters you identified, including potential structures and mechanisms that permit viable financing, sources of financing and required changes to legislation, regulations and OPG's constating documents to facilitate the implementation of the financing plan in a commercial manner. The plan will also include assurances that implementation of the financing plan will have no adverse impacts on OPG, its operating assets or the manner in which they are regulated. I note the Province's commitment to provide OPG with the necessary assurances with respect to recovery of the principal, interest, and operating and other costs of any financing. This will be an important consideration for the OPG Board.

OPG has engaged financial and legal advisors with significant capital markets expertise, including experience in the United States where a number of state-owned utilities have put in place highly rated financing for costs that are to be recovered over a long period of time. Work on OPG's financing plan is being guided by these advisors and precedents.

The Board will provide you with our recommendation and plan in the timeframe requested.

Sincerely,

Bernard Lord
Board Chair

cc: The Honourable Charles Sousa, Minister of Finance
Scott Thompson, Deputy Minister of Finance
Serge Imbrogno, Deputy Minister of Energy
Gadi Mayman, CEO, Ontario Financing Authority
Jeff Lyash, President and CEO, Ontario Power Generation

From:	Gadi Mayman
To:	Ronald Kwan; Mike Manning; Ken Kandeepan
Cc:	Anna Strathy; Gavin He
Subject:	Fw: Minister Letter to OPG
Date:	Tuesday, April 18, 2017 11:04:17 AM
Attachments:	MC-2017-750 Outgoing.pdf

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: Tuesday, April 18, 2017 11:02 AM
To: Gadi Mayman
Subject: FW: Minister Letter to OPG

From: Katona, Keley (ENERGY)
Sent: April 13, 2017 5:42 PM
To: Hume, Steen (ENERGY); Calwell, Carolyn (ENERGY/MEDEI/MRI); Nelms, Scott (MOF)
Subject: Fw: Minister Letter to OPG

From: Keley.Katona@ontario.ca
Sent: Thursday, April 13, 2017 5:41 PM
To: HARTWICK Ken -FINANCE
Cc: Imbrogno, Serge (ENERGY); KING Catriona -OFFCORPSEC
Subject: Re: Minister Letter to OPG

Attached is the signed letter.

From: Katona, Keley (ENERGY)
Sent: Thursday, April 13, 2017 3:49 PM
To: HARTWICK Ken -FINANCE
Cc: Imbrogno, Serge (ENERGY); KING Catriona -OFFCORPSEC
Subject: Re: Minister Letter to OPG

Thanks Ken, we've incorporated your changes.

Sent from my iPad

On Apr 13, 2017, at 2:49 PM, HARTWICK Ken -FINANCE <ken.hartwick@opg.com> wrote:

> Keley
>
> See the recommended changes to the letter. I reviewed these with the accounting team and both are needed to ensure the effective consolidation of the SPV into OPG. In particular the first change is critical. The second is important as the activity we undertake needs to be in the interest of OPG recognizing that the ratepayer impact is

critical.

Thanks

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<20170413-Letter from Province to OPG-LSB ESP Consolidated v2_clean.docx>

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

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Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

APR 1 3 2017

MC-2017-750

Mr. Bernard Lord
Board Chair
Ontario Power Generation Inc.
700 University Avenue, 19th Floor
Toronto ON M5G 1X6

Dear Mr. Lord:

I am writing to provide Ontario Power Generation Inc. (OPG) with additional detail regarding elements of Ontario's Fair Hydro Plan as announced by the government on March 2, 2017. Given OPG's active participation in the electricity market and its expertise in rate regulated accounting and investment stewardship over significant pension and nuclear funds, I am writing specifically to request OPG's involvement in the implementation of the Global Adjustment (GA) refinancing that will be required in relation to changes to the GA proposed as a component of Ontario's Fair Hydro Plan.

The Government of Ontario proposes to take steps to lower electricity bills by 25 per cent for a typical residential electricity consumer relative to what those bills would otherwise have been without Ontario's Fair Hydro Plan. Changes to the GA are proposed to be a component of the 25 per cent rate relief. This proposed 25 per cent rate relief measure would also be inclusive of the 8 per cent rebate that is already in effect under the *Ontario Rebate for Electricity Consumers Act, 2016* and the savings that are anticipated to result from the proposed shifting of the Ontario Electricity Support Program (OESP) and the Rural or Remote Rate Protection (RRPP) program costs from ratepayers to provincial revenues.

I am requesting that OPG, working with the Ministry of Energy, the Independent Electricity System Operator (IESO), the Ontario Financing Authority (OFA) and their respective advisors, consider and recommend a plan for financing mechanisms that could achieve the Province's objectives with respect to Ontario's Fair Hydro Plan, all in accordance with any legislation and regulations currently in place, or that may subsequently be implemented, with respect to facilitating Ontario's Fair Hydro Plan.

In particular, the Province would like OPG's financing plan to consider, among other things, structures and methods that would permit refinancing of a portion of the GA in order to reduce electricity prices for specified electricity consumers, with the costs of the refinancing to be recovered over a period of no more than 30 years, all in accordance with any legislation and regulations currently in place, or that may subsequently be implemented, with respect to facilitating Ontario's Fair Hydro Plan. I would also expect OPG's financing plan to include:

.../cont'd

I. Potential structures for the financing, which may include, as appropriate, a special purpose vehicle (SPV) created for the financing;

II. Potential financing mechanisms and instruments, including senior debt and subordinated debt; and

III. Identification of the capital markets and jurisdictions that can be accessed to refinance a portion of the GA.

The Province recognizes the need to provide OPG with the necessary assurances with respect to recovery of the principal, interest and operating and other costs of any financing, and will consider the specific requirements identified by OPG and its advisors, including in any future legislation and regulations that would govern the mechanics and requirements of the financing entity. I would also request that your plan identify any amendments to OPG's governing legislation and constating documents needed to facilitate the implementation of the financing plan in a commercial manner.

I would further expect that OPG's financing plan would be implemented in an effective and cost-efficient manner by OPG balancing the need to protect the interests of ratepayers and the financial health of OPG. I would also further expect that OPG will ensure that any of its proposed borrowing and other activities under its financing plan take into account the "inter-generational" approach that the Province is intending to provide in executing Ontario's Fair Hydro Plan.

I look forward to receiving a detailed plan that has the support of the OPG Board of Directors by June 1, 2017.

Sincerely,

Glenn Thibeault
Minister

c: Hon. Charles Sousa, Minister of Finance
Scott Thompson, Deputy Minister of Finance
Serge Imbrogno, Deputy Minister of Energy
Gadi Mayman, CEO, Ontario Financing Authority
Jeffrey Lyash, President and CEO, Ontario Power Generation

From:	Gadi Mayman
To:	Mike Manning; Ken Kandeepan; Ronald Kwan
Cc:	Anna Strathy; Usman Zahid
Subject:	Fwd: Financing Plan under The Ontario Fair Hydro Plan Act 2017 ("the Act")
Date:	Wednesday, December 20, 2017 10:22:16 AM
Attachments:	December 20 2017 letter to Hon. Glenn Thibeault.pdf ATT00001.htm

---

Begin forwarded message:

From: "LORD Bernard -BOARDCHAIR" <bernard.lord@opg.com>
To: "'glenn.thibeault@ontario.ca'" <glenn.thibeault@ontario.ca>
Cc: "Serge Imbrogno (ENERGY)" <Serge.Imbrogno@ontario.ca>, "Charles Sousa (MOF)" <Charles.Sousa@ontario.ca>, "Scott Thompson (CAB)" <Scott.Thompson@ontario.ca>, "Gadi Mayman" <Gadi.Mayman@ofina.on.ca>, "LYASH Jeffrey -PRESIDENT" <jeffrey.lyash@opg.com>
Subject: Financing Plan under The Ontario Fair Hydro Plan Act 2017 ("the Act")

Good Morning,

Please see the attached letter from Bernard Lord.

Regards,

Rosemarie

Rosemarie Hoilett
Executive Assistant - Jeff Lyash President & CEO | Bernard Lord Board Chair
Ontario Power Generation
700 University Ave | H19-A24
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ONTARIO POWER GENERATION

Bernard Lord
Board Chair

700 University Avenue Toronto, ON M5G 1X6

Tel: 416-592-2115
bernard.lord@opg.com

Wednesday, December 20, 2017

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Hand Delivered and sent via email

Dear Minister Thibeault,

Re: Financing Plan under the Ontario Fair Hydro Plan Act, 2017 (the "Act")

I am writing further to our recent exchange of letters and the most recent one dated May 19, 2017, regarding the delivery of a Financing Plan by OPG as Financial Services Manager of the Fair Hydro Trust under the Act. I am pleased to advise that OPG's delivery of the Financing Plan was confirmed by the OPG Board on November 22, 2017, and it is enclosed herewith.

Sincerely,

Bernard Lord
Board Chair

cc (by email):
The Honourable Charles Sousa, Minister of Finance
Scott Thompson, Deputy Minister of Finance
Serge Imbrogno, Deputy Minister of Energy
Gadi Mayman, CEO, Ontario Financing Authority
Jeff Lyash, President and CEO, Ontario Power Generation

Enclosure

FAIR HYDRO TRUST
FINANCING PLAN

December 18, 2017

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A. Background

In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* (the **Act**), to establish a framework under which the costs and benefits associated with the Government of Ontario's (the **Province**) Clean Energy Initiatives are to be fairly allocated between present and future consumers of electricity under Ontario's Fair Hydro Plan (Fair Hydro Plan or FHP). The Act requires the Ontario Energy Board (**OEB**) to set rates that would reduce electricity bills for a proxy regulated rate specified consumer by 25 percent commencing on July 1, 2017. The total bill reduction is comprised of the 8 percent rebate equivalent to the Provincial portion of the Harmonized Sales Tax, the shifting of funding for electricity support programs from electricity bills to provincial revenues, and by decreasing electricity rates for specified consumers paying the Regulated Price Plan (**RPP**) rate. The OEB is providing a Global Adjustment reduction credit for non-RPP specified consumers.

The reduction in electricity bills will result in a shortfall in the Independent Electricity System Operator's (**IESO**) collections, which will need to be financed in order to pay the underlying global adjustment costs (**GAC**). The objective of the Fair Hydro Plan Program (**FHP Program**) is to refinance a portion of the deferred GAC over a longer period.

Under the Act, OPG is appointed as the Financial Services Manager (**FSM**) and is given the authority to, among other things, establish and manage one or more financing entities to raise debt financing (referred to as "Funding Obligations") for the purposes of the Act. The Act requires the Minister of Energy (**MOE**) to calculate the Fair Allocation Amount and for the FSM to incur Funding Obligations that, subject to refinancing, reasonably align with the Fair Allocation Amount, as adjusted by any readjustment amount.

The following attendant regulations were enacted in support of the Act:

- *Ontario Regulation 206/17 General* (**General Regulation**) provides details on specific requirements of the Act, in particular, the requirements for the Financing Plan.
- *Ontario Regulation 195/17 Fair Adjustment* provides details on rate reductions up to April 30, 2019 for specified consumers under the Act.
- *Ontario Regulation 196/17 Invoicing Requirements* provides details on information to be included with the invoice for specified consumers under the Act.

Under sections 21(1) and 21(2) of the Act, OPG, as FSM, has an obligation to prepare a Financing Plan in accordance with the Act and regulations, and to deliver it to the Minister of Energy. Under section 21(6) of the Act, the FSM has the right to amend the Financing Plan from time to time, without affecting any Clean Energy Adjustment that has already been determined or any Funding Obligations that have already been incurred before the amendment.

This Financing Plan was prepared based on the information available to, and the views of, OPG at the time this Financing Plan was prepared (or amended, as applicable). This Financing Plan also includes forward-looking information, which is subject to change. Actual outcomes and results may differ materially from what is expressed, implied or forecasted due to, but not limited to, changes in underlying assumptions relating to the Fair Allocation Amount, interest rates, investor interest, market capacity, market conditions, and credit rating assessments. References made to the "current Fair Allocation Amount" pertains to the Fair Allocation Amount received by OPG from the MOE at the end of September 2017. Terms that are capitalized and not defined

herein have meanings ascribed to the same terms as in the Act or in the General Regulation. All amounts presented are in Canadian dollars.

1. Financing Entity – Fair Hydro Trust

Trustees

In December 2017, OPG as FSM, appointed Computershare Trust Company of Canada to act as the third party issuer trustee (Computershare or **Issuer Trustee**). Following its appointment, the Fair Hydro Trust (the **Trust**) was established as a financing entity contemplated in the Act through a declaration of trust. The Trust is structured to be bankruptcy remote from OPG. The Issuer Trustee is empowered under the declaration of trust to appoint, employ or contract with any person for the transaction of the Trust's activities. Under the Management Agreement between the Trust (by the Issuer Trustee) and OPG, the Trust appointed OPG as its agent to provide services and perform duties for the Trust in planning, implementing and administering the debt financing for the FHP Program.

In December 2017, OPG as FSM, appointed BNY Trust Company of Canada, as the third party indenture trustee (BNY or **Indenture Trustee**). The Indenture Trustee will be acting on behalf of all specified creditors, who are all persons who may have contractual claims against the Trust under the FHP Program agreements contemplated by the Master Trust Indenture (**MTI**) governing the debt issued by the Trust.

Unitholders

The Trust will carry on activities for the benefit of its unitholders outlined below:

Table 1: Fair Hydro Trust Unitholders

Unitholder	Number of Units Held
FHP2017 Inc., a wholly-owned subsidiary of OPG	1,000,000
BNY, as Indenture Trustee	1
Total Units Outstanding	**1,000,001**

Trust Capitalization Structure

The Trust will be 100 percent debt financed and the contemplated source of funding is summarized in Table 2.

Table 2: Type and Source of Debt Funding

Tranche and Debt Type	Source of Funding	% of Total Funding Requirement
Tranche A Senior Debt	Capital Markets	51%
Tranche B Subordinated Debt	OPG via Province	39%
Tranche C Junior Subordinated Debt	OPG via Province	5%
	OPG via Capital Markets	5%

The Trust will issue senior debt in the capital markets to finance 51 percent of the total funding requirement related to the deferred GAC (Tranche A). The financing platform was developed to allow the Trust access to both the Canadian and United States (**US**) markets in order to optimize pricing, provide flexibility, and market capacity. Further details on the types of financing that can be utilized are outlined under the heading *Current Funding Options*.

Through periodic equity injections in OPG, the Province is expected to provide 44 percent of the total funding requirement throughout the duration of the FHP Program. OPG will invest the proceeds from the equity injections into the Trust, with 39 percent in Tranche B as subordinated debt and five percent in Tranche C as junior subordinated debt.

OPG will invest the remaining five percent of the total funding requirement in Tranche C as junior subordinated debt, using internally generated funds or proceeds raised from debt issuances from the public markets.

2. OPG's Duties and Responsibilities

Financial Services Manager under the Act

OPG, as FSM, will perform its duties and responsibilities under the Act and its attendant regulations. These include, but are not limited to, the following:

- Establish one or more financing entities to incur Funding Obligations for the FHP Program
- Prepare a written Financing Plan to be used by OPG to evaluate the incurrence of Funding Obligations to acquire and finance a portion of the GAC deferral
- Ensure that Funding Obligations are incurred in a manner that is consistent with the Financing Plan
- Forecast the cash flow requirements of the financing entities
- Determine the monthly Clean Energy Adjustment for a particular Reference Period
- Administer the Investment Asset on behalf of the financing entities
- Establish and charge fees to the financing entities to recover costs and expenditures and to earn a return

- Seek the best terms available at the time of incurrence of a Funding Obligation, having regard to other financing transactions of similar size and type
- Apply debt proceeds to purchase an Investment Interest or repay or redeem outstanding debt
- Consider the interests of specified consumers with respect to stable and predictable electricity rates
- Deal with related parties on arm's length terms
- Fulfil various reporting requirements to stakeholders

Manager under the Management Agreement

OPG has also entered into a management agreement with the Issuer Trustee, on behalf of the Trust, whereby all of the powers and duties of managing the Trust have been delegated to OPG as the manager. The duties and responsibilities associated with this role includes:

- Determining whether to incur Funding Obligations to acquire an Investment Interest or to refinance existing Funding Obligations;
- Negotiating and entering into program agreements;
- Maintaining accounts and banking records;
- Preparing any offering documents furnished by the Trust to prospective purchasers of Funding Obligations; and
- Preparing financial statements and tax filings on behalf of the Trust.

OPG's entitlement to fees, as FSM, is subject to the payment priorities outlined in the MTI and summarized in Section C, *Application of Recovery Amounts to Funding Obligations,* Figure 5. The FSM is not entitled to resign from its duties or terminate the management agreement as long as Funding Obligations remain outstanding. OPG may be terminated by the Issuer Trustee, with the consent of the Indenture Trustee, or by the Indenture Trustee in accordance with the MTI.

3. Fair Allocation Amount and the Financing Plan

The Fair Allocation Amount, including the readjustment amount where applicable, is an amount calculated under the Act and the regulations by the MOE for every Reference Period over the term of the FHP Program. It is intended to allocate the estimated Clean Energy Costs and Clean Energy Benefits fairly among specified consumers.

The FSM is required to prepare a Financing Plan under the Act to evaluate whether Funding Obligations should be incurred by the Trust. OPG is to have regard to certain prescribed principles (outlined in detail in Section B below), including that Funding Obligations should be incurred so that the estimated Finance Amount that would become due and payable during a Reference Period will, subject to refinancing, reasonably align with the Fair Allocation Amount determined in respect of such Reference Period, as adjusted by a readjustment amount where applicable. In other words, the Financing Plan should contemplate the issuance of Funding Obligations from time to time, with terms that would result in Clean Energy Adjustments being payable by specified consumers to ensure that they are bearing their fair share of the costs of providing Clean Energy Benefits. The Act also provides that each Funding Obligation is deemed

to be consistent with the Financing Plan and to provide for the reasonable alignment of the estimated Finance Amount with the Fair Allocation Amount.

Figures 1 and 2 illustrate the FHP Program's financing profile over the next 30-year period.

Figure 1: Fair Hydro Trust Debt Balance

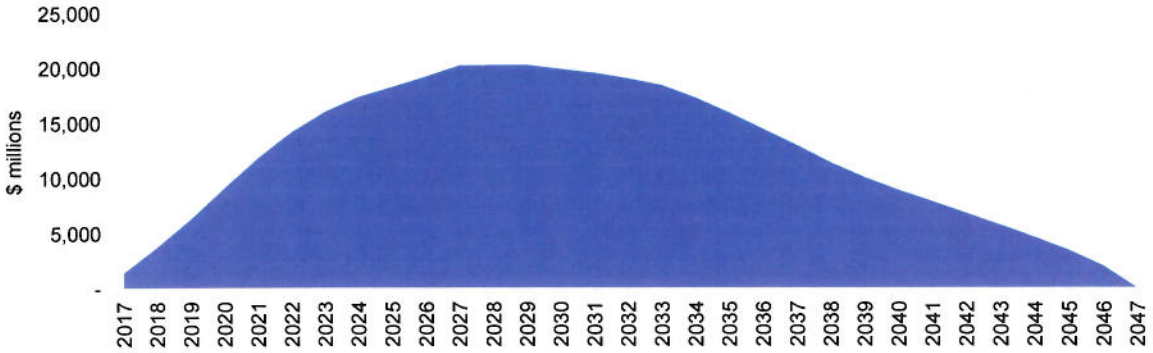
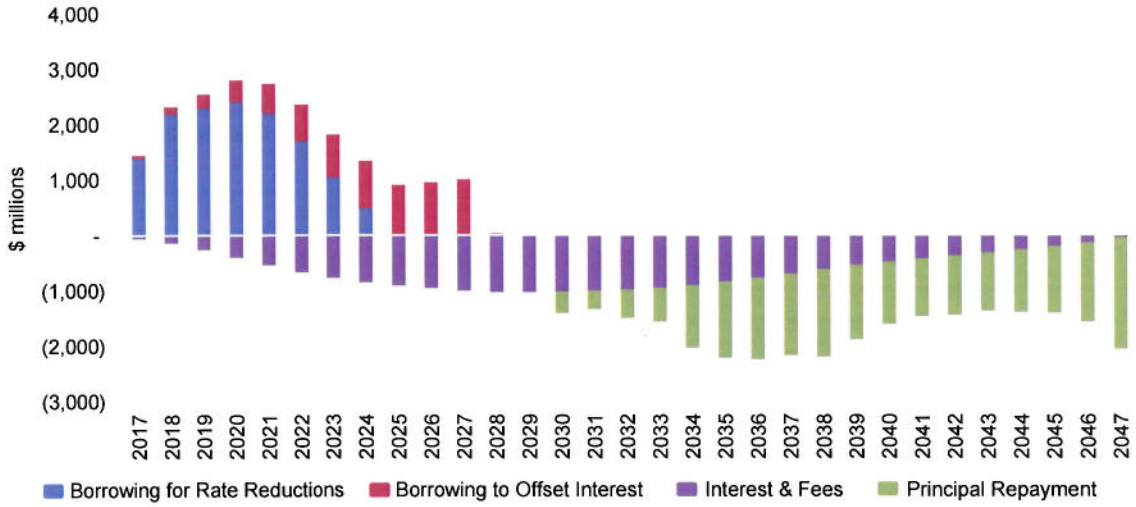


Figure 2: Fair Hydro Trust Borrowing and Repayment Profile



The Fair Allocation Amount is a net amount, either positive or negative, equal to the difference between the following:

1) estimated costs of Clean Energy Initiatives without adjustment; and
2) a re-profiling of the costs in item 1) plus:
    a. the estimated operating and financing costs of the FHP Program, and
    b. the repayment of the readjustment amount.

A negative Fair Allocation Amount in any Reference Period generally represents a period of borrowing, and a positive Fair Allocation Amount generally represents a period of principal repayment.

In a Reference Period when the Fair Allocation Amount is negative, the operating and financing costs of the FHP Program are shown in the Fair Allocation Amount calculation as an increase in the debt of the FHP Program. This treatment is equivalent to increasing the amount of the deferred GAC. The repayment of the related debt is included in the Fair Allocation Amount calculation to establish that all debt will be repaid by the end of the FHP Program. During these periods, operating and financing costs of the FHP Program are considered to align with the Fair Allocation Amount as long as these costs do not exceed the corresponding components in the Fair Allocation Amount calculation in any Reference Period by more than +/- 15 percent. If these costs exceed the corresponding components of the Fair Allocation Amount by more than +/- 15 percent, the FSM will take reasonable actions in accordance with the Act and regulations to align to the Fair Allocation Amount. Variability in costs is expected throughout the FHP Program as the Fair Allocation Amount was calculated on a forecast basis. Accordingly, any variability that is less than +/- 15 percent is deemed to be within an acceptable range.

Assessment for Reasonable Alignment

The Act stipulates that the Financing Plan must reasonably align with Fair Allocation Amount. This requirement is expected to be achieved through the consistent application of the following methodology, guidelines, and steps throughout the term of the FHP Program:

- Maintain a financial model that captures the Funding Obligations requirements of the Trust. Translate the funding requirements into expected cash flows by determining the related interest amounts, reserve requirements, fees, principal repayment, and the Trust's operating costs. This exercise will be performed for each Reference Period over the term of the program.
- Determine and assess the following:
    - For Reference Periods when the Fair Allocation Amount is negative, determine whether the forecast cash flow requirements is less than or equal to the financing and operating costs reflected in the Fair Allocation Amount as additional debt of the Trust. If the forecast cash flow requirements exceed the addition to the debt in the Fair Allocation Amount by more than +/- 15 percent, determine the cause of the variance. In these situations, the FSM will take reasonable actions in accordance with the Act and regulations to align to the Fair Allocation Amount.
    - For Reference Periods when the Fair Allocation Amount is positive, determine whether the forecast cash flow requirements is less than or equal to the Fair Allocation Amount. If the forecast cash flow requirements exceed the Fair Allocation Amount by more than +/- 15 percent, determine the cause of the variance. In these situations, the FSM will take reasonable actions in accordance with the Act and regulations to align to the Fair Allocation Amount.
- Due to the timing of the collection of cash flows, the General Regulation contemplates the use of reserve accounts. Provisions for reserves are excluded from the reasonable alignment assessment as these amounts are required to allow the Trust to incur the Funding Obligations. In addition, the reserve balances will be credited to specified consumers at the end of the term through the true-up mechanism if they are not required to satisfy terms of any Funding Obligation agreements pursuant to the MTI. Refer to *Financing Reserve and Capital Accounts* for more information on reserve accounts.

- Utilize and apply an accrual methodology when determining costs of the program, except for debt issuance costs, principal repayments, and reserve requirements.

The FSM will establish a methodology for assessing reasonable alignment at such time when a new Fair Allocation Amount letter is received from the MOE.

B. Principles and Assumptions of the Financing Plan

This section outlines the various principles and assumptions that guided the development of this Financing Plan in accordance with the Act and section 14 of the General Regulation. The same principles and assumptions will apply to all subsequent revisions of the Financing Plan, if required.

The FSM is required to make reasonable assumptions regarding the following matters:

1. IESO Deferral for Future Months

The FSM will base its expectation of the IESO deferrals on the most current version of the Fair Allocation Amount and readjustment amounts provided by the MOE. Actual IESO deferrals and forecasts of near term deferrals, if available, will be used to guide forecast deferrals over the next quarter.

2. Future Transfers of Portions of the IESO's Regulatory Asset

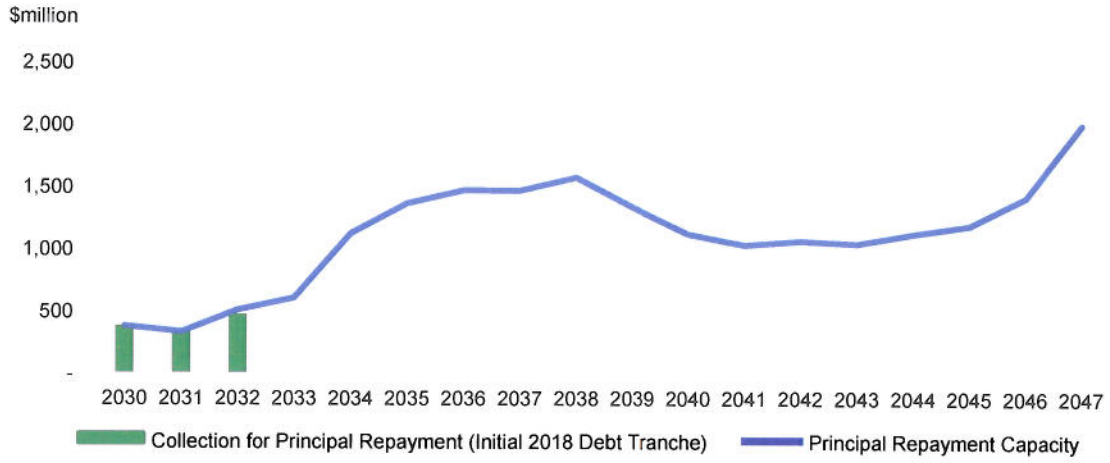
The Trust anticipates periodic purchases of Investment Assets from the IESO when the cumulative balance of its regulatory assets is large enough to be financed and when effective financing options are available to the Trust. The market capacity for both long-term and short-term debt financing will also be key elements to consider when determining the most cost efficient option.

3. Term to Maturity of Funding Obligations

Initial Term Debt Tranche – 2018 Borrowing

The forecast debt profile for the Trust based on the current Fair Allocation Amount received from the Province at the end of September 2017 indicates that principal repayments can commence in 2030 (see Figure 3). However, the principal repayment amount for that year is expected to be relatively small at approximately $400 million for the year or about $200 million for each six-month Reference Period. Accordingly, principal repayment of the initial 2018 term debt tranche is expected to commence in 2032 when the cumulative principal repayment amount reaches approximately $1 billion, which indicates a minimum term for the initial debt issuance of approximately 15 years. This offering is expected to include $500 million of senior notes, which is a sizeable amount to ensure sufficient liquidity and marketability. Subsequently, principal repayment increases to approximately $1.5 billion annually or $0.75 billion for each Reference Period by around 2035 allowing for larger single maturities.

Figure 3: Principal Repayment Profile Based on Current Fair Allocation Amount



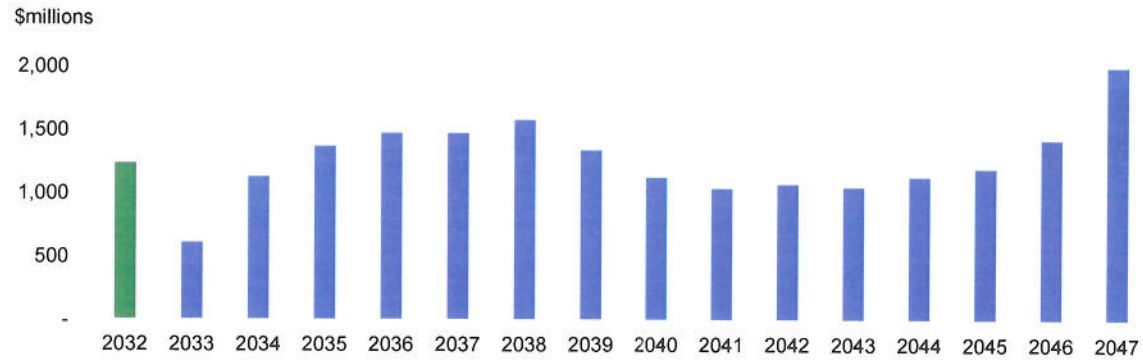
This length of term for an asset-backed security (**ABS**) has no precedence in the Canadian market where terms are typically 10 years or less. Therefore, it is expected that a higher premium will be required to attract investors. Refer to Table 3 under the heading *Interest Rates* for the indicative current pricing range for all debt tranches, including senior debt.

For a new issuer such as the Trust offering a unique program, a strategy of issuing a 15-year term paper may not provide an optimal initial pricing given the absence of a specific credit curve for the Trust. It is expected that at program inception, the Trust will issue debt to cover both short and long-term exposures. The terms of maturities will be staggered, up to year 30, with maturities capped at the projected Fair Allocation Amount and readjustment amount, during each six-month Reference Period. In addition, consideration for a combination of characteristics established by the Fair Allocation Amount curve and investor interest will drive the term of a Funding Obligation.

Indicative Debt Maturities for Borrowings

Using the current Fair Allocation Amount, the forecast debt maturities over the life of the FHP Program was derived in Figure 4 for illustrative purposes only and is current as of the date of this Financing Plan. Actual debt maturities may differ materially from what is illustrated in Figure 4 primarily due, but not limited to, future changes in the Fair Allocation Amount.

Figure 4: Indicative Debt Maturities Using the Current Fair Allocation Amount



The key objective when determining the indicative debt maturities in Figure 4 is to align the annual amount of debt maturities with the principal repayment capacity under the Fair Allocation Amount curve. In years where the principal repayment capacity is less than $500 million, the debt maturities will fall in subsequent years where the cumulative maturities do not exceed the cumulative principal repayment capacity. This type of decision will be made along with other considerations such as size of each issuance to ensure liquidity (and thus, cost efficiency). As this schedule is based on the current Fair Allocation Amount curve and its underlying assumptions, a shift in the curve and/or any changes in the assumptions will result in changes to this indicative debt maturity schedule.

4. Refinancing

The MTI requires the Trust to establish and maintain a deposit account in the name of the Indenture Trustee for a refinancing account held for the benefit of the Indenture Trustee and specified creditors. All proceeds arising from notes and borrowings related to refinancing shall be deposited to this refinancing account.

Debt refinancing may occur under the following scenarios:

- When original financing is incurred, the short end of the yield curve is more cost efficient than the long end, on a relative basis;
- The Fair Allocation Amount or readjustment amount is updated; and
- In line with the provisions of the Act, no Clean Energy Adjustments will be collected from specified consumers between July 1, 2017 and April 30, 2021. Accordingly, any debt maturities during this period will need to be refinanced.

Refinancing decisions will be guided by the Trust's ability to secure cost efficient long-term financing from investors and the maximum principal repayment profile dictated by the Fair Allocation Amount curve. Given the current Fair Allocation Amount, the FSM expects that debt issuances during the moratorium period will be a minimum of 15-year terms.

However, if market conditions are such that short-term notes (e.g. 5-year notes), along with hedging the refinancing of these notes after 5 years, could be more cost effective than issuing longer term notes, the FSM may consider such a strategy instead of issuing 15-year notes. In the event of an update to the Fair Allocation Amount or the readjustment amount that leads to a significant change in the profile whereby collections of CEAs could start earlier, short-term notes could also be issued.

5. Cash Flow Requirements

The Trust's cash flow requirements to meet its contractual obligations include, but are not limited to, the following:

- Payment of taxes, if any
- Reimbursing the FSM for costs and expenditures outlined in sections 10.2 (3) and 10.13 (3) of the General Regulation and summarized under the heading *Fair Hydro Trust Costs and Expenditures*
- Interest and fees on all outstanding borrowings
- Scheduled principal repayments

- Deposits or transfers to reserve accounts required by the MTI and summarized under the heading *Financing Reserve and Capital Accounts*
- OPG's fees as FSM as summarized under the heading *Financial Services Manager's Fees*
- Termination payments to defaulting derivative counterparties, if applicable

Refer to Figure 5 in Section C, *Application of Recovery Amounts to Funding Obligations* for the cash flow receipts' payment priority.

6. Current Funding Options and Related Terms and Conditions

To achieve cost efficiencies, the following funding vehicles could be utilized in either the Canadian or US markets (except for the subordinated debt), from time to time, depending on the financing requirement, as well as market capacity and relative pricing at the time of issuance:

- **Short Term**: asset-backed commercial paper (**ABCP**) conduit and revolving bank lines of credit in the Canadian market
- **Medium to Long-Term**: term ABS and privately placed debt securities in either the Canadian or US markets
- **Subordinated Debt**: to be provided by OPG

Syndicated Short-Term Warehousing Facility

Short-term notes will be issued by the Trust to fund short-term borrowing requirements. The amount outstanding will be periodically refinanced and repaid by long-term funding from the capital markets once the cumulative amount of the Investment Asset available to be purchased is approximately $300 million to $500 million. This warehouse facility is expected to be utilized on a monthly basis to fund the Investment Asset purchases from the IESO.

The Trust will be securing a warehouse facility agreement with a bank syndicate comprising of CIBC, RBC, and Goldman Sachs for $800 million under a 2-year committed term, which would be primarily funded through their ABCP conduit.

Revolving Bank Lines of Credit

This type of funding option provides the Trust with a warehouse facility under which principal amounts can be advanced, repaid and again advanced during a committed revolving period. This bank funding option will be utilized when it is more cost effective than short-term notes.

Term ABS

ABS are notes that will be backed by the Trust's Investment Asset and issued under the MTI. The specific terms and conditions of each series, class or tranche of notes will be set forth in a supplemental indenture and, if applicable, a terms document authorizing that series, class or tranche.

To minimize financing costs, term ABS bullet bonds will be used rather than amortizing bonds, which require an additional premium by investors. The current intent is to issue term ABS notes in the 15 to 25 year term to fill out the yield curve based on the Fair Allocation Amount and investor demand.

Subordinated Debt

Concurrent with every issuance of senior debt by the Trust, it is expected that OPG will acquire subordinated debt in an amount not to exceed 49 percent of all outstanding debt of the Trust at any time. The subordination of OPG's debt investment plays an important credit enhancement role, which is expected to minimize the cost of senior debt tranches in the external market by garnering a higher rating through some differentiation. The subordinated debt will assume substantially all of the liquidity and deferral risk for the structure. Accordingly, the cash flow payment waterfall in Figure 5 reflects this subordination structure.

The credit rating for the subordinated debt will be dependent on the rating agency assessment and evaluation of the stress credit scenarios. It is expected that there will be a minimum of one rating category differential between each debt tranche.

The interest rate applicable to subordinated debt is expected to be the aggregate of:

- The applicable base rate, which is the relevant senior debt rate, plus
- The applicable spread, which represents the additional interest, in basis points, over the base rate that will apply to the relevant subordinated debt. This rate will be established by OPG through an annual survey of market spreads from a syndicate of banks.

The subordinated debt will maintain a minimum of one rating to allow for appropriate benchmarking/pricing. A simple average of the market spreads will determine the rate, excluding the highest and lowest rates in the survey sample. The terms of the subordinated debt will be finalized prior to the initial debt issuance.

For the short-term subordinated debt lending facility, the banking syndicate will provide OPG with comparable short-term lending spreads on committed bank credit facilities on an annual basis (i.e. ratings based on a pricing grid). A simple average of the market spreads will determine the rate, excluding the highest and lowest rates in the survey sample.

The process will be consistent with the Subordinated Debt Pricing Protocol between OPG, as FSM, and the Ontario Financing Authority.

7. Currency and Interest Rate Hedging Programs

As the FHP Program develops over time, the Trust will consider interest rate and currency swaps and other hedging instruments, as required. Refer to the Section C, *Risk Mitigation Strategies* for further details on hedging and other instruments that could be used by the Trust.

8. Fair Hydro Trust Costs and Expenditures

The costs and expenditures incurred by OPG as FSM on behalf of the Trust will be in accordance with sections 10.2 (3) and 10.13 (3) of the General Regulation as amended in November 2017.

Specifically, the costs and expenditures incurred by the FSM include, but are not limited to, the following:

1. Underwriters or selling agents for Funding Obligations.
2. Banking fees, including but not limited to structuring fees or work fees.
3. Fees of issuing and paying agents for Funding Obligations.
4. Fees of trustees.

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.
6. Fees of legal counsel.
7. Rating agency fees.
8. Filing or registration fees.
9. Direct costs of OPG for employees whose work consists exclusively of the provision of services to the Trust in relation to prescribed matters.
10. Costs and expenditures incurred on behalf of any financing entity in connection with OPG's duties under the Act in relation to the financing entity.
11. Costs and expenditures incurred in relation to a management agreement between OPG as FSM and any financing entity, where the agreement provides for the reimbursement of the costs and expenditures.

The costs and expenditures incurred directly by the Trust, as well as the fees of the FSM and the costs and expenditures incurred by the FSM on behalf of the Trust, are Finance Amounts that can be recovered by the Trust (as carrying costs) from the IESO until July 2021 and thereafter through Clean Energy Adjustments charged to specified consumers.

9. Interest Rates

As the FHP Program is expected to last until 2047, it is appropriate to assume that long-term debt rates are the primary components of the financing costs for the overall program. In estimating indicative interest rates for each tranche and debt type, the following key considerations and assumptions were utilized:

- The base case credit rating assumptions are as follows:
  - Target of "AAA" for Tranche A – Senior Debt,
  - "A" for Tranche B – Subordinated Debt which is dependent on the senior debt credit rating, and
  - "BBB" for Tranche C – Junior Subordinated Debt
- Using the projected Province of Ontario long bond rate of 4 percent plus a 25 basis points premium to reflect the securitization structure, the estimated indicative pricing over the life of Tranche A – Senior Debt is 4.25 percent
- For comparative purposes, the current pricing using the Province of Ontario long bond rate of 3.0 percent plus the same 25 basis points premium was included to reflect the current low interest rate environment
- A higher return on the subordinated debt is required to compensate for incremental risks assuming:
  - Rating agencies attribute a lower rating to the subordinated debt relative to the senior debt due to the lower priority in the cash flow waterfall (refer to Figure 5 in Section C, *Application of Recovery Amounts to Funding Obligations*)
  - Senior debt's rating needs to be credit enhanced to address collection and liquidity risks

To achieve cost efficiencies, the Trust was established with a tiered debt structure to achieve a higher credit rating for the senior debt and to maximize market capacity by accessing the AAA market to achieve cheaper financing costs overall. The following table summarizes the indicative pricing range by debt tranche:

Table 3: Indicative Pricing by Debt Tranche

Tranche and Debt Type	Risk Profile	Source	% of Total Funding Requirement	Rating Category Estimate	Current Pricing	Potential Rating Range	Price Based on Rating Range
Tranche A Senior Debt	Lowest Risk	Capital Market	51%	AAA	3.25%	AAA – AA	3.25% – 3.75%
Tranche B Subordinated Debt	Medium Risk	OPG via Province	39%	A	4.5%	AA – A	4.0% – 4.5%
Tranche C Junior Subordinated Debt	Highest Risk	OPG via Province	5%	BBB	5.5%	A – BBB	5.0% – 5.75%
		OPG via Capital Markets	5%				
Weighted Average					**4.0%**		**3.75% – 4.5%**

The credit range for each debt tranche will be determined by the overall credit strength of the financing structure and its resilience under various credit stress scenarios. The rating agencies' assessment of the limited guarantee to bondholders provided by the Change of Law Protection Agreement, discussed under the heading *Indemnifications*, is one of the major factors that will influence the final ratings of each debt tranche. In addition, in assessing credit stress, the following factors, among others, will be considered: (i) declining energy usage throughout the securitization period, (ii) forecast collections in peak months not materializing, and (iii) declining consumption equal to the largest absolute annual forecast error. The market capacity for securitization notes is predominantly available for AAA-rated notes, limited for AA-rated notes, and not tested or developed for A-rated or lower. The pricing estimates provided in Table 3 reflect these credit and liquidity factors. Debt pricing will be finalized at the time of the initial issuance.

10. Finance and Capital Reserve Accounts

Section 5(1) of the General Regulation stipulates that the Finance Amount shall include any amounts the Trust deposits into capital or finance reserve accounts as required under the governing documents of the Funding Obligations (i.e. the MTI). The accounts also act as a credit enhancement feature in support of the Trust borrowings. Any unused balance in the segregated trust accounts at the end of the term will be credited to specified consumers. Refer to Figure 5 in Section C, *Application of Recovery Amounts to Funding Obligations*, for the priority order of deposits into the reserve accounts.

Section 7.02 of the MTI between the Trust and the Indenture Trustee specifies the establishment and maintenance of the following key reserve accounts:

Finance Reserve Accounts

Program Cash Reserve Account

The Trust shall establish and maintain a Program Cash Reserve Account, a deposit account in the name of the Indenture Trustee with an eligible institution. This finance reserve account shall be under the control of the Indenture Trustee for the benefit of the Indenture Trustee and the specified creditors. The Trust is required to deposit to this account the Program Cash Reserve Required Amount during the Reference Period commencing May 1, 2021, being an amount equal to 0.50 percent of the aggregate outstanding principal amount of the senior Funding Obligations, subordinated Funding Obligations and junior subordinated Funding Obligations after giving effect to all settlements on such payment date, or such lesser amount that satisfies the rating agency condition. Amounts available from the collection account will be deposited from time to time in the Program Cash Reserve Account to maintain the balance at the then Program Cash Reserve Required Amount.

Series Finance Reserve Account

From time to time, the Trust may establish a Series Finance Reserve Account, a deposit account in the name of the Indenture Trustee with an eligible institution. Each Series Finance Reserve Account shall be under the control of the Indenture Trustee for the benefit of the Indenture Trustee and the applicable specified creditors. This finance reserve account may be established for the purpose of allowing the Trust to reserve funds to pay finance charges (including, without limitation, interest and payments under derivative agreements) for a series of issuer Funding Obligations.

Capital Reserve Account

Series Capital Reserve Account

From time to time, the Trust may establish a Series Capital Reserve Account, a deposit account in the name of the Indenture Trustee with an eligible institution. Each Series Capital Reserve Account shall be under the control of the Indenture Trustee for the benefit of the Indenture Trustee and the applicable specified creditors. This capital reserve account may be established for the sole purpose of allowing the Trust to accumulate funds to be used to make repayments in respect of Funding Obligations. Details of any period of accumulation and the amounts to be accumulated shall be specified in the related Funding Obligation agreement.

11. Indemnifications

The following forms of indemnities are expected to be issued for the FHP Program:

Change of Law Protection Agreement

The Change of Law Protection Agreement provides bondholders a limited guarantee in the event of a protection event and acts as a credit enhancement for the Trust's senior debt. The guarantee will be triggered if:

i. the Province changes the Fair Hydro legislation/regulations or passes other legislation/regulation; or

ii. a change in the organization or structure of the IESO is implemented or Ontario's electricity market is undertaken at the initiative of the Province or an entity controlled by the Province; or

iii. the Act is declared invalid/unconstitutional.

in each case, in a way that adversely affects the ability of the Trust to receive amounts in respect of its Investment Interest so that it can pay funding obligations covered by the agreement, after taking into account and having regard to (i) any funds available at such time to apply to pay such Funding Obligations, including in any finance reserve account, (ii) the availability of any credit enhancement to which the Trust is a party and (iii) any reasonably expected potential effect of a true-up amount under the Act in the Reference Period immediately following the occurrence of an event described above.

Upon the occurrence of a protection event, the Province is required to pay the approved obligations owing by the Trust as they become due and payable provided that the Province has a right of subrogation to receive amounts that the Trust has a right to receive.

Change of Law Process Agreement

Prior to entering into to the Change of Law Process Agreement between OPG and the Province, OPG as FSM provided the Province with an initial forecast setting out OPG's expectations regarding the aggregate maximum amount of debt to be incurred during the initial 24-month forecast period commencing December 1, 2017. This initial forecast amount is designated as the "Initial Protection Agreement Maximum". The Province did not disagree with the initial forecast or the Initial Protection Agreement Maximum on the basis of an apparent inaccuracy in the initial forecast, an inconsistency between the initial forecast and the initial Financing Plan, or as a result of the Initial Protection Agreement Maximum being more than the initial forecast. Pursuant to the Change of Law Process Agreement, between 9 and 12 months prior to the expiry of the initial 24-month forecast period (and every subsequent 24-month forecast period), OPG as FSM will provide the Province with an updated forecast of the aggregate maximum amount of debt to be issued such 24-month forecast periods. This amount, combined with such future amounts with which the Province has not disagreed, will be the Protection Agreement Maximum.

Table 4 provides the expected debt issuance amounts for the next 24-month period as consistent with the Financing Plan and submitted to the Province pursuant to the agreement.

Table 4: Initial Protection Agreement Maximum

Forecast Period Start Date	Forecast Period End Date	Expected Amount of Debt Issuance ($M)
December 1, 2017	December 31, 2017	$1,179
January 1, 2018	December 31, 2018	$2,591
January 1, 2019	November 30, 2019	$2,553
Initial Protection Agreement Maximum:		**$6,323**

Issuer Trustee

Each of the Issuer Trustee and its related parties will be indemnified out of the trust property from and against all liabilities, obligations, losses, damages, penalties, taxes, claims, actions, investigations, proceedings, costs, expenses or disbursements of any kind arising out of, among other things, the declaration of trust or any other program agreement, the administration of the Trust's assets or the action or inaction of the Issuer Trustee's agents, except for its own fraud, willful misconduct, bad faith or negligence.

Limited Recourse

The obligation of the Trust to pay principal and interest on the Funding Obligations is subject to the allocation and payment provisions in the MTI and the applicable Funding Obligation agreement and limited to amounts available from the collateral. Neither the Indenture Trustee, OPG nor the Issuer Trustee in its individual capacity will be personally liable for the payment of the principal or interest on the notes or any other Funding Obligation, or for the Trust's covenants and agreements contained in the MTI.

12. Financial Services Manager's Fees

All fees charged by OPG to the Trust will be in accordance with the provisions of the General Regulation.

Subject to OEB approval, OPG is entitled to the following:

- For 2017, OPG will receive $3.1 million and an amount to cover up-front costs incurred between June 1 and December 31, 2017 by OPG on behalf of the Trust (e.g. legal fees, rating agency fees, trustee fees). The $3.1 million includes a $600,000 fee and $2.5 million to cover costs incurred prior to June 1, 2017. The expenses between June 1 and December 31, 2017 will also include direct costs of OPG employees who are dedicated exclusively to Fair Hydro matters.
- For January 2018 to March 2019, OPG will receive a general fee consisting of (i) a monthly base fee equal to 7.5 basis points, divided by 12, multiplied by the average outstanding debt of the Trust, calculated on a monthly basis, (ii) a variable fee that is calculated based on how the interest rate for external funding tranches for that period compare to forecast interest rates for the period (and which fee is limited to ± 2 percent of 5 percent of the total

external funding tranches issued in the period), and (iii) third-party expenses and direct employee costs of dedicated Fair Hydro employees.

- For April 2019 to March 2020, and every 12-month period thereafter, OPG will make submissions to the OEB on the base fee, variable fee and expenses. The base fee will be based on comparable fees charged by full-service managers of securitization vehicles (and other similar funds). The variable fee will be calculated in the same manner noted above, but with a refresh of forecast interest rates for the relevant period. For 2019 onward, the expenses will include direct employee costs of dedicated Fair Hydro employees only if the fees of comparable managers also include such direct costs.

A written confirmation from OPG's external auditor or another external auditor is required to accompany each submission to the OEB for the recovery of expenditures incurred by OPG on behalf of the Trust. The report shall confirm the accuracy of the costs and expenditures charged to the Trust, that such amounts were incurred by OPG, and the amounts were paid to third parties (with the exception of direct employee costs).

C. Other Considerations

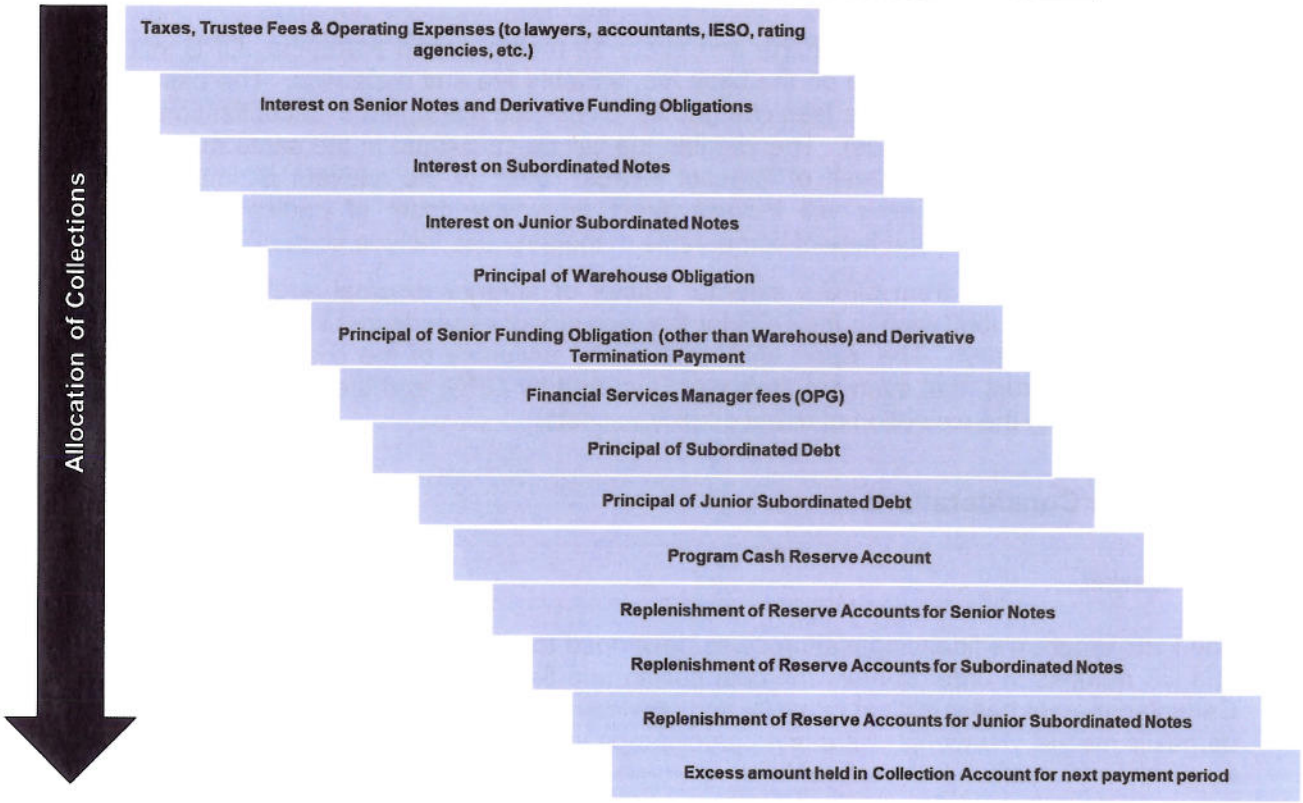
1. Market

The FHP Program's financing platform was developed to allow for access to both the Canadian and US markets in order to have the best pricing and flexibility options. To the extent that the Canadian market has sufficient capacity and provides cost efficiency, priority will be given to the domestic market. However, there is no precedence in the Canadian market for term ABS notes longer than 10 years, nor the size of funding required by the FHP Program. Due to this, the ability to access the US market provides the program additional financing capacity in the event that the Canadian market cannot support the financing requirement. The FSM will make its decision on which market to access on a deal-by-deal basis.

2. Application of Recovery Amounts to Funding Obligations

Section 7.04(e) of the MTI outlines the payment priorities for the Trust's receipt of cash flows. Figure 5 below summarizes the significant components of the payment waterfall.

Figure 5: Payment Waterfall for Fair Hydro Trust Cash Collections



Payment Priorities

On each payment date, all amounts on deposit in the collection account will be paid out in the following order of priority:

1. to pay (A) all taxes exigible for which a governmental authority is given priority over the specified creditors under the laws of the applicable jurisdiction, and then (B) fees, expenses and reimbursements owing to the Issuer Trustee and the Indenture Trustee up to a maximum aggregate amount of equal to $150,000, multiplied by the number of series of senior Funding Obligations outstanding on the payment date, divided by 12;
2. to pay (A) interest, fees and other amounts owing in respect of senior debt and (B) amounts payable to derivative counterparties other than termination payments;
3. to pay interest, fees and other amounts owing in respect of subordinated debt;
4. to pay interest, fees and other amounts owing in respect of junior subordinated debt;
5. to pay principal owing in respect of warehouse debt;
6. to pay (A) principal owing in respect of senior debt to the extent required to satisfy any payment of principal; and (B) termination payments owing to derivative counterparties where the derivative counterparty is not the defaulting party or the sole affected party;
7. to pay fees, expenses, reimbursement and indemnity amounts owing to the FSM;
8. to pay principal owing in respect of subordinated debt to the extent required to satisfy any payment of principal;

9. to pay principal owing in respect of junior subordinated debt to the extent required to satisfy any payment of principal;
10. to deposit to the Program Cash Reserve Account, if the amount on deposit is less than the required amount;
11. to replenish any reserve account in respect of senior debt, the amount required pursuant to the applicable Funding Obligation agreement;
12. to replenish any reserve account in respect of subordinated debt, the amount required pursuant to the applicable Funding Obligation agreement;
13. to replenish any reserve account in respect of junior subordinated debt, the amount required pursuant to the applicable Funding Obligation agreement;
14. to be held in the collection account for distribution in the above order of priority on the next payment date; or (ii) after all Funding Obligations have been paid and discharged, and all other amounts have been paid in full, to pay to the Trust.

3. Risk Mitigation Strategies

Currency Risk

If the Canadian market cannot support the financing capacity of the FHP Program in the future and/or it is less cost efficient than the US market at the time of each subsequent debt issuance, the Trust will access the US market for long-term financing.

Under this scenario, hedges will be considered to mitigate currency exposure. For the initial debt issuance in 2017, it is anticipated that funding will be sourced from the Canadian market only as it is expected to be more cost efficient and there is sufficient market capacity.

Interest Rate and Refinancing Risk

The FHP Program is expected to span over a 30-year period until 2047 with various series of notes expected to be issued at various maturity dates. Given the long-term timeline of the program, it is subject to interest rate and refinancing risk.

Interest rate hedges, including bond forwards and/or forward start interest rate swaps, will be considered in the future to mitigate potential interest rate risk and/or refinancing risk in a cost-efficient manner.

Legal and Political Risk

Given the long-term nature of the FHP Program and the potential for changes in provincial policy, the lenders requires that changes to any legislation (including the Act and its attendant regulations) that would materially and adversely affect the ability of the Trust to service interest or principal payments on its debt would be addressed by the Province.

As discussed in Section B, *11. Indemnifications*, the Change of Law Protection Agreement provides bondholders a limited guarantee that the Province will cover the approved obligations of the Trust if the guarantee is triggered.

4. Tax Minimization Strategies

Beneficiary – FHP2017 Inc.

The majority unitholder and beneficiary of the Trust is exempt from federal tax under section 149 of the *Income Tax Act, Canada* and from Ontario tax under section 27 of the *Ontario Taxation Act, 2007*.

The beneficiary is subject to payments in lieu of federal and provincial income taxes (**PILs**). In order to minimize the tax associated with the Fair Hydro Plan, an exemption from PILs payable on income from the Trust has been requested for the beneficiary. This will result in a reduction in the income tax costs related to the Financing Plan.

Fair Hydro Trust

Trust income will be fully distributed to unitholders to ensure that there is no tax payable by the Trust.

D. Execution Plan for First Investment Asset Purchase

The regulatory asset balance available to be purchased from the IESO is expected to be approximately $1.2 billion, representing accumulated GAC deferrals up to the end of November 2017. Given there will be better market access in January 2018 compared to December 2017, the short-term warehouse facility will be utilized to fund the senior debt tranche of the funding requirement for the first investment asset purchase. Accordingly, the size of the short-term funding is approximately $600 million, representing 51 percent of the funding structure allocation from capital markets. OPG will purchase short-term subordinated and junior subordinated debt issued by the Trust for approximately $580 million, representing the remaining 49 percent of the total funding requirement.

Key Activities

The following table outlines the key activities for funding the first purchase of the Investment Asset:

Activity	2017/2018 Timeline
Province's Equity Contribution and Warehouse Facility Closing & Funding to Purchase Investment Asset	December 21, 2017
Term Debt Rating Agencies' Confirmation of Ratings	Week of January 8, 2018
Marketing & Roadshow	Week of January 22, 2018
Term Debt Pricing	Week of February 5, 2018
Term Debt Closing & Funding	T+5 of Pricing Date

E. Glossary of Terms

In this Financing Plan, the capitalized terms used have the following meanings from the Act:

"**Clean Energy Adjustment**" means the amount determined under section 15 and payable by specified consumers

"**Clean Energy Benefits**" means the value of the benefits determined to be derived by or accruing to specified consumers as a result of the clean energy initiative, including as a result of clean energy costs

"**Clean Energy Costs**" means the value of the costs allocated to specified consumers as a result of the clean energy initiative, including as a result of past, present and expected costs incurred in respect of,

a) the amounts to be paid or reflected by the IESO in adjustments made under section 25.33 of the Electricity Act, 1998 or any provision that is the successor to that provision, which relate to contracts or amounts for,
    (i) renewable energy generation or capacity,
    (ii) conservation and demand management,
    (iii) energy storage,
    (iv) energy efficiency,
    (v) natural gas generation and capacity, excluding contracts relating to amounts payable by the IESO under section 78.2 of the Ontario Energy Board Act, 1998 and excluding such other contracts as may be prescribed,
b) payments made or expected to be made under section 78.5 of the *Ontario Energy Board Act, 1998*, and
c) such other costs or estimated costs as may be prescribed

"**Clean Energy Initiative**" means the policies of the Government of Ontario related to,

a) eliminating coal generation and fostering the growth of and investment in clean, modern and reliable energy sources and technologies,
b) removing barriers to and promoting opportunities for clean and renewable energy sources and technologies,
c) promoting conservation, demand management and energy efficiency, and
d) investing in energy infrastructure to ensure a clean, modern and reliable system

"**Fair Allocation Amount**" means an amount calculated under section 20 of the Act

"**Finance Amount**" means the finance amount determined in accordance with the regulations

"**Funding Obligation**" means a payment obligation incurred by or on behalf of an investment interest owner to fund its ownership of an investment interest or a payment obligation that meets such other criteria as may be prescribed

"**Investment Asset**" means the rights and interests described in section 29 of the Act

"**Investment Interest**" means,

a) an ownership interest in the investment asset, and
b) in circumstances where the ownership interest is transferred, the rights and benefits specified in the agreement under which the interest is transferred

"**Reference Period**" means,

a) the period beginning on July 1, 2017 and ending on October 31, 2017, and
b) during the period beginning on November 1, 2017 and ending on either April 30, 2047 or such later day as may be prescribed,
   (i) every six-month period following the period mentioned in clause (a), or
   (ii) any period shorter than six months, as may be prescribed

From:	Perkins, Michael (ENERGY)
To:	Communications, Finance (MOF)
Subject:	Minister"s Mailed Correspondence -- April 18, 2017
Date:	Tuesday, April 18, 2017 2:54:36 PM
Attachments:	MC-2017-750 Outgoing.pdf

Hello,

Attached please find the Minister of Energy's outgoing correspondence, mailed April 18, 2017.

- MC-2017-750 — Ministry generated letter to Ontario Power Generation (OPG) Board Chair re: financing mechanisms for Ontario Fair Hydro Plan (OFHP).
- MC-2017-735 — Ministry generated letters (5) to federal ministers re: connecting First Nation communities.

Best,
Michael

Michael Perkins, MA | Correspondence Assistant
Corporate Correspondence Unit | Ministry of Energy
900 Bay Street, 4th Floor, Hearst Block, Toronto ON, M7A 2E1
michael.perkins@ontario.ca | 416-212-7023

Please consider the environment before printing this e-mail.

Ministry of Energy

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Ontario

APR 1 3 2017

MC-2017-750

Mr. Bernard Lord
Board Chair
Ontario Power Generation Inc.
700 University Avenue, 19th Floor
Toronto ON M5G 1X6

Dear Mr. Lord:

I am writing to provide Ontario Power Generation Inc. (OPG) with additional detail regarding elements of Ontario's Fair Hydro Plan as announced by the government on March 2, 2017. Given OPG's active participation in the electricity market and its expertise in rate regulated accounting and investment stewardship over significant pension and nuclear funds, I am writing specifically to request OPG's involvement in the implementation of the Global Adjustment (GA) refinancing that will be required in relation to changes to the GA proposed as a component of Ontario's Fair Hydro Plan.

The Government of Ontario proposes to take steps to lower electricity bills by 25 per cent for a typical residential electricity consumer relative to what those bills would otherwise have been without Ontario's Fair Hydro Plan. Changes to the GA are proposed to be a component of the 25 per cent rate relief. This proposed 25 per cent rate relief measure would also be inclusive of the 8 per cent rebate that is already in effect under the *Ontario Rebate for Electricity Consumers Act, 2016* and the savings that are anticipated to result from the proposed shifting of the Ontario Electricity Support Program (OESP) and the Rural or Remote Rate Protection (RRPP) program costs from ratepayers to provincial revenues.

I am requesting that OPG, working with the Ministry of Energy, the Independent Electricity System Operator (IESO), the Ontario Financing Authority (OFA) and their respective advisors, consider and recommend a plan for financing mechanisms that could achieve the Province's objectives with respect to Ontario's Fair Hydro Plan, all in accordance with any legislation and regulations currently in place, or that may subsequently be implemented, with respect to facilitating Ontario's Fair Hydro Plan.

In particular, the Province would like OPG's financing plan to consider, among other things, structures and methods that would permit refinancing of a portion of the GA in order to reduce electricity prices for specified electricity consumers, with the costs of the refinancing to be recovered over a period of no more than 30 years, all in accordance with any legislation and regulations currently in place, or that may subsequently be implemented, with respect to facilitating Ontario's Fair Hydro Plan. I would also expect OPG's financing plan to include:

.../cont'd

I. Potential structures for the financing, which may include, as appropriate, a special purpose vehicle (SPV) created for the financing;

II. Potential financing mechanisms and instruments, including senior debt and subordinated debt; and

III. Identification of the capital markets and jurisdictions that can be accessed to refinance a portion of the GA.

The Province recognizes the need to provide OPG with the necessary assurances with respect to recovery of the principal, interest and operating and other costs of any financing, and will consider the specific requirements identified by OPG and its advisors, including in any future legislation and regulations that would govern the mechanics and requirements of the financing entity. I would also request that your plan identify any amendments to OPG's governing legislation and constating documents needed to facilitate the implementation of the financing plan in a commercial manner.

I would further expect that OPG's financing plan would be implemented in an effective and cost-efficient manner by OPG balancing the need to protect the interests of ratepayers and the financial health of OPG. I would also further expect that OPG will ensure that any of its proposed borrowing and other activities under its financing plan take into account the "inter-generational" approach that the Province is intending to provide in executing Ontario's Fair Hydro Plan.

I look forward to receiving a detailed plan that has the support of the OPG Board of Directors by June 1, 2017.

Sincerely,

Glenn Thibeault
Minister

c: Hon. Charles Sousa, Minister of Finance
Scott Thompson, Deputy Minister of Finance
Serge Imbrogno, Deputy Minister of Energy
Gadi Mayman, CEO, Ontario Financing Authority
Jeffrey Lyash, President and CEO, Ontario Power Generation

From:	Hume, Steen (ENERGY)
To:	Ronald Kwan
Cc:	Hilary Cox (ENE)
Subject:	OFHP
Date:	Friday, October 13, 2017 10:17:01 AM
Attachments:	Letter from the Minister of Energy - MC-2017-1757.pdf

Good morning Ron. In response to your question, attached is the Fair Allocations Amount (FAA) letter from our Minister to OPG. The appendix provide a data table that will likely be helpful.

Thanks, Steen

From: Ronald Kwan [mailto:Ronald.Kwan@ofina.on.ca]
Sent: October 10, 2017 1:38 PM
To: Hume, Steen (ENERGY)
Subject: FHP

Hi Steen,

Would you be able to share the latest projection on the annual GA deferral. The Provincial share of financing is needed to update the Province's interest on debt forecast for fiscal planning and borrowing and debt management purposes.

Thanks,
Ron

This message, including any attachments, is meant only for the use of the individual(s) to whom it is intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

Ministry of Energy

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Ontario

MC-2017-1757

SEP 2 8 2017

Mr. Bernard Lord
Board Chair
Ontario Power Generation
700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord:

Re: *Ontario Fair Hydro Plan Act, 2017* and the Fair Allocation Amount

I write pursuant to my obligation under subsection 20(4) of the *Ontario Fair Hydro Plan Act, 2017* (the Act) to provide Ontario Power Generation (OPG), acting in its capacity as Financial Services Manager under the Act, with the Fair Allocation Amount (FAA) in respect of each reference period from July 1, 2017 to April 30, 2047. Terms used in this letter that are also used in the Act and the related regulations have the definitions provided for in the Act and the related regulations.

The FAA for each reference period, determined in accordance with subsection 20(1) of the Act and Ontario Regulation 206/17 (General) made under the Act, including associated estimated financing costs, shall be the amount set out in Schedule "A" to this letter. I would also note that the estimated financing costs, including estimated fees, contained within the FAAs are reflective of input from OPG staff.

Also included in Schedule "A" are the readjustment amounts for the first four reference periods and additional readjustments that are expected to be made beyond the first four reference periods, reflective of past overpayments of clean energy costs between 2005 and 2017 and consistent with the Government of Ontario's commitment to hold rate increases, for four years, to not more than the rate of inflation. The recovery of these readjustment amounts and related interest costs have been included in the calculation of the FAAs in Schedule "A" as per subsection 20(2) of the Act and related regulations.

.../cont'd

To support the calculation of the FAA, the potential useful life of clean energy assets has been examined and a fair allocation of clean energy costs associated with those assets over time provided, so that specified consumers in the future pay their fair share for the benefits that they receive from those clean energy assets.

I trust OPG in its role as Financial Services Manager, under the Act, will prepare the Financing Plan in accordance with subsection 21(3) of the Act that reasonably aligns with these FAAs. I would also note that under the Act, the FAA amounts included in Schedule "A" may be updated in consultation with OPG staff from time to time. We expect that the FAA amounts will be updated on a periodic basis to reflect actual Independent Electricity System Operator (IESO) deferrals from actual Global Adjustment costs and consumer rate reductions and actual costs of the financing entities under Ontario's Fair Hydro Plan.

I would also note that Ministry of Energy staff would provide OPG staff with the residential bill assumptions from the upcoming 2017 Long-Term Energy Plan to provide further context in relation to the amounts included in Schedule "A".

We look forward to continuing to work with you as this initiative moves forward.

Sincerely,

Glenn Thibeault
Minister

Enclosure

c: Serge Imbrogno, Deputy Minister of Energy
Jeff Lyash, President and CEO, Ontario Power Generation

SCHEDULE "A" – FAIR ALLOCATION AMOUNT

REFERENCE PERIOD	FAIR ALLOCATION AMOUNT (FAA) ($ million)	READJUSTMENT AMOUNT (RA) ($ million)
2017-Jul	-931	-74
2017-Nov	-779	-341
2018-May	-629	-470
2018-Nov	-562	-564
2019-May	-535	-617
2019-Nov	-462	-721
2020-May	-431	-781
2020-Nov	-348	-784
2021-May	-98	-250
2021-Jul	-213	-546
2021-Nov	-233	-697
2022-May	-197	-657
2022-Nov	-130	-501
2023-May	-98	-429
2023-Nov	-50	-287
2024-May	-27	-220
2024-Nov	21	-73
2025-May	45	-
2025-Nov	95	-
2026-May	121	-
2026-Nov	141	-
2027-May	152	-
2027-Nov	224	-
2028-May	262	-
2028-Nov	376	-
2029-May	437	-
2029-Nov	612	-
2030-May	706	-
2030-Nov	678	-
2031-May	673	-
2031-Nov	719	-
2032-May	751	-
2032-Nov	767	-
2033-May	785	-
2033-Nov	937	-
2034-May	1,024	-
2034-Nov	1,075	-
2035-May	1,113	-
2035-Nov	1,115	-
2036-May	1,129	-
2036-Nov	1,095	-
2037-May	1,091	-
2037-Nov	1,091	-
2038-May	1,105	-
2038-Nov	992	-
2039-May	948	-
2039-Nov	848	-

REFERENCE PERIOD	FAIR ALLOCATION AMOUNT (FAA) ($ million)	READJUSTMENT AMOUNT (RA) ($ million)
2040-May	809	-
2040-Nov	756	-
2041-May	738	-
2041-Nov	725	-
2042-May	728	-
2042-Nov	697	-
2043-May	690	-
2043-Nov	692	-
2044-May	701	-
2044-Nov	698	-
2045-May	705	-
2045-Nov	753	-
2046-May	786	-
2046-Nov	945	-
2047-May	1,376	-

From:	John Kim
To:	Ronald Kwan
Cc:	Francisco Chinchon; Bruno Amara
Subject:	OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 11:46:29 AM
Attachments:	2017 03 14 OPG concurrence letter v6_markup1.docx

Hi Ron,

Pls. see attached with proposed edits from SIFB to the concurrence letter. We are still looking at the deck and will be forthcoming soon.

They have a meeting with Serge at 3:30 so would appreciate any comments soon.

John

Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority
Ph: 416-212-6996
Email: john.kim@ofina.on.ca

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing subsequent unit refurbishments after Unit 2 is successfully returned to service.

We continue to support the planned operation of Pickering units up to 2024 as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to seek concurrence to proceed with ongoing Pickering operation after the necessary regulatory approvals are complete.

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the liability estimates~~costs to consumers~~ for future decommissioning and long-term management of waste from Ontario's nuclear fleet. ~~plants. In addition, the segregated nuclear funds set aside under ONFA have reached fully funded status.~~ With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations in a prudent manner~~, the decision to fund these costs now provides security for future generations of Ontarians~~.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Ali Ghiassi, Chief of Staff, Ministry of Finance
Scott Thompson, Deputy Minister, Ministry of Finance
Serge Imbrogno, Deputy Minister, Ministry of Energy

From:	Bruno Amara
To:	Ronald Kwan; John Kim
Cc:	Francisco Chinchon; Adam Prokop
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 2:05:46 PM
Attachments:	2017 04 11 OPG Business Plan Review v7_Markup7.pptx

Hmm? Yes, maybe I made one edit too many. I think the first part is indeed OK. Maybe just the last edit "per month per year" I think is already implied.

From: Ronald Kwan
Sent: Monday, April 24, 2017 1:55 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hi Bruno,

That seems to change the meaning. Is that right?

Ron

From: Bruno Amara
Sent: April-24-17 13:52
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

I found 2nd bullet slide 9 convoluted. See edit. But nevermind if it's too much editing.

From: Ronald Kwan
Sent: Monday, April 24, 2017 12:53 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hi John,

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Sent: April-24-17 12:17
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
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Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority
Ph: 416-212-6996
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Ontario

MINISTRY OF
ENERGY

OPG Business Plan

May 2017

Context

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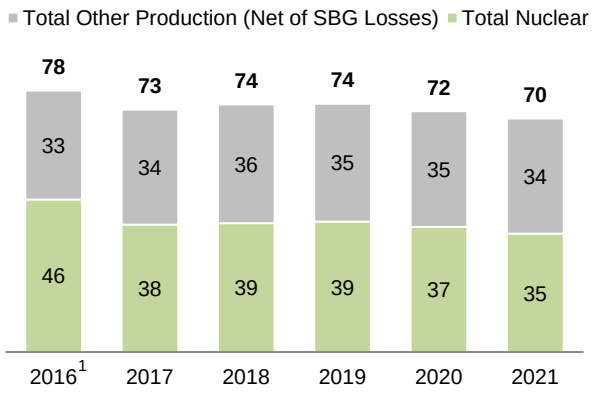
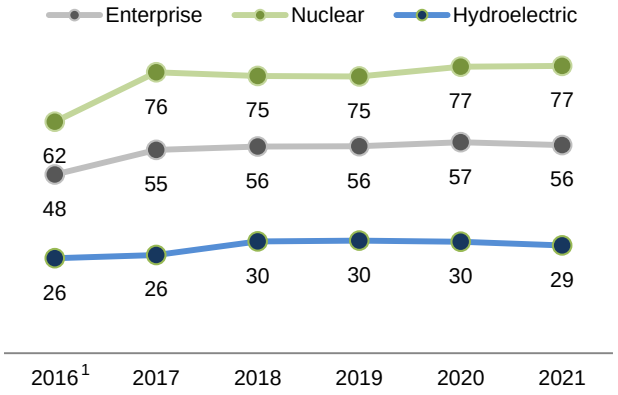
Production (TWh)



Total Generating Cost ($/MWh)



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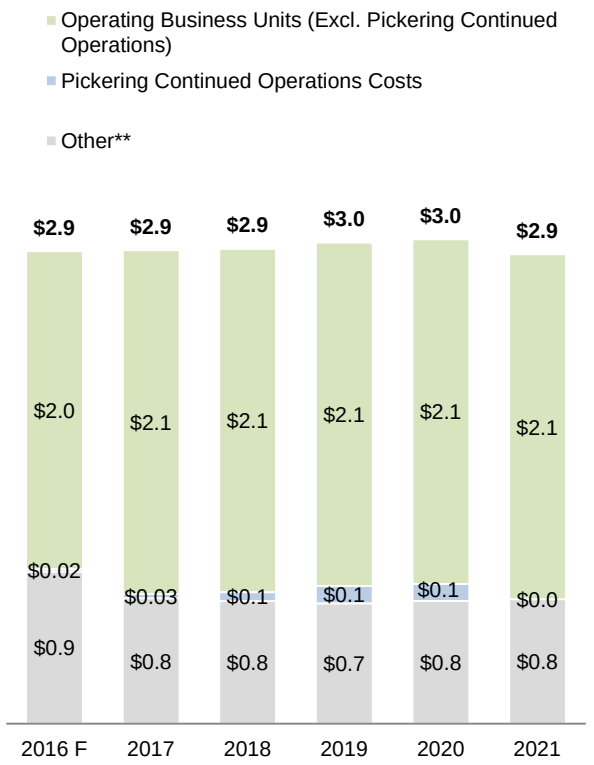

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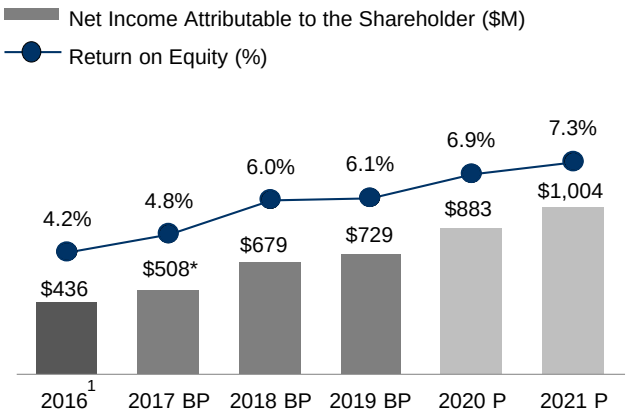
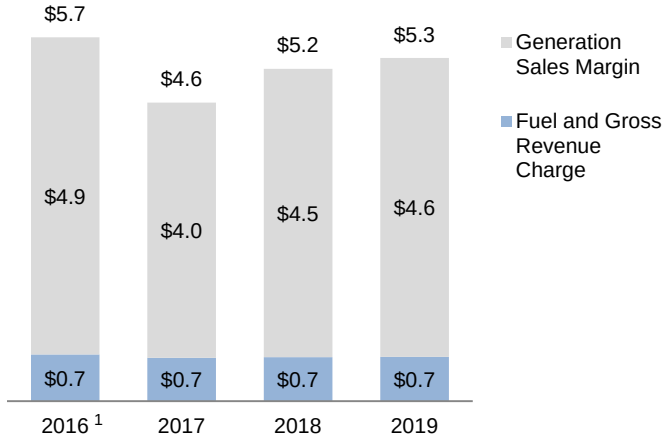
Net Income ($M) and ROE (%)



Revenue Margin ($B)



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- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
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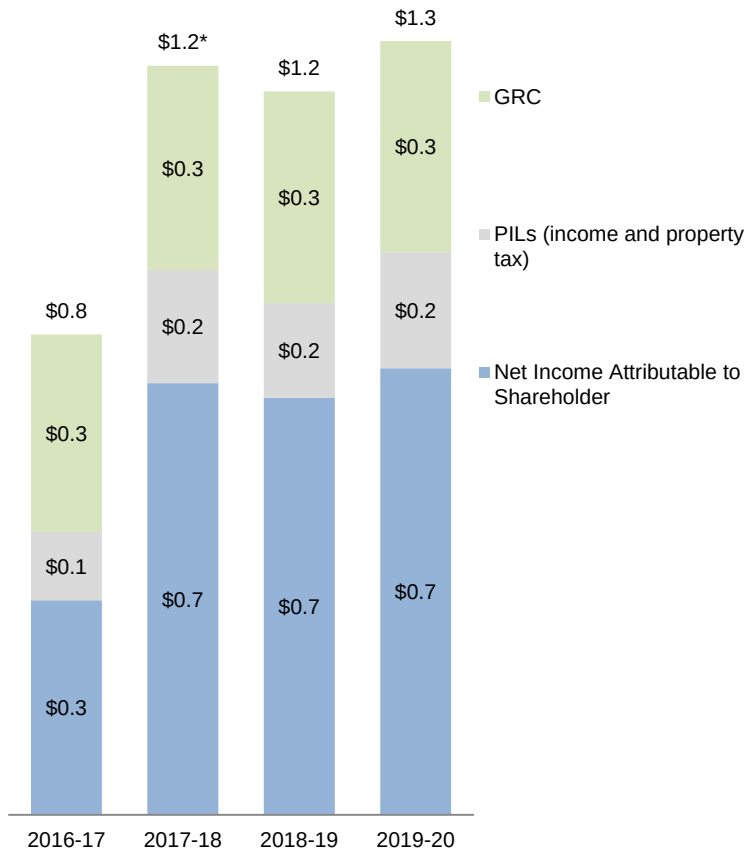
Total Fiscal Revenues ~~Shareholder Return~~ ($B)



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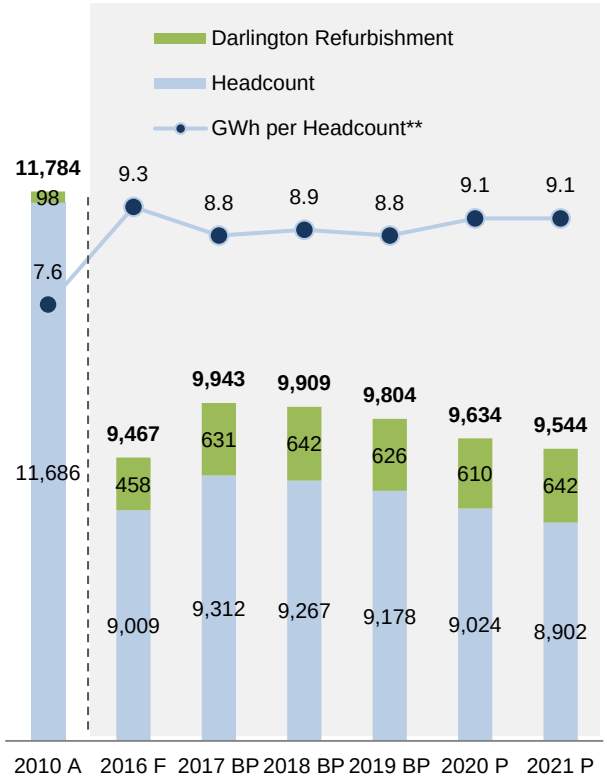
1. Business Plan Overview

e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG has saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~60 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations

Ongoing Operations Regular Headcount and Productivity



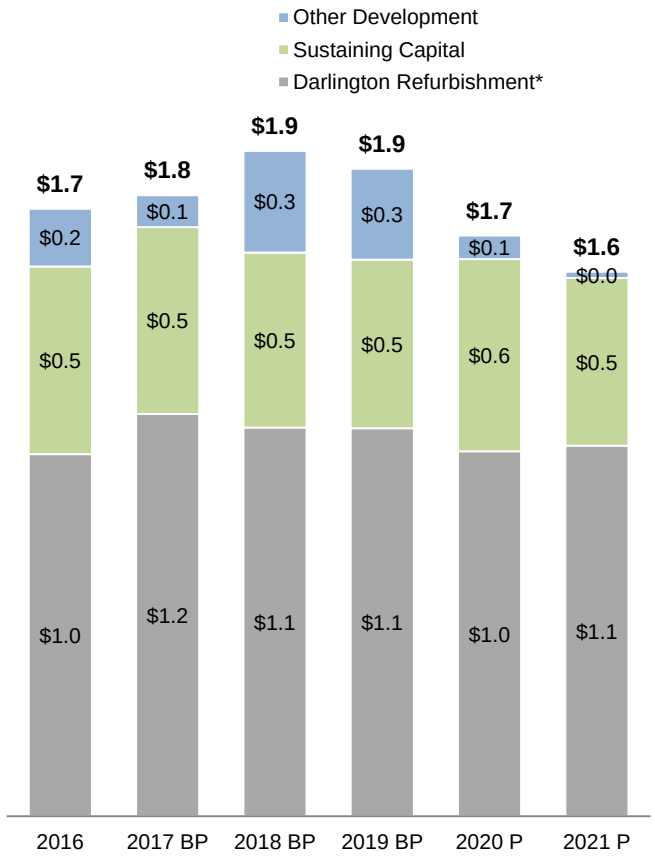
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

1. Business Plan Overview

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew II
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Developments:** Investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

2. Other Considerations

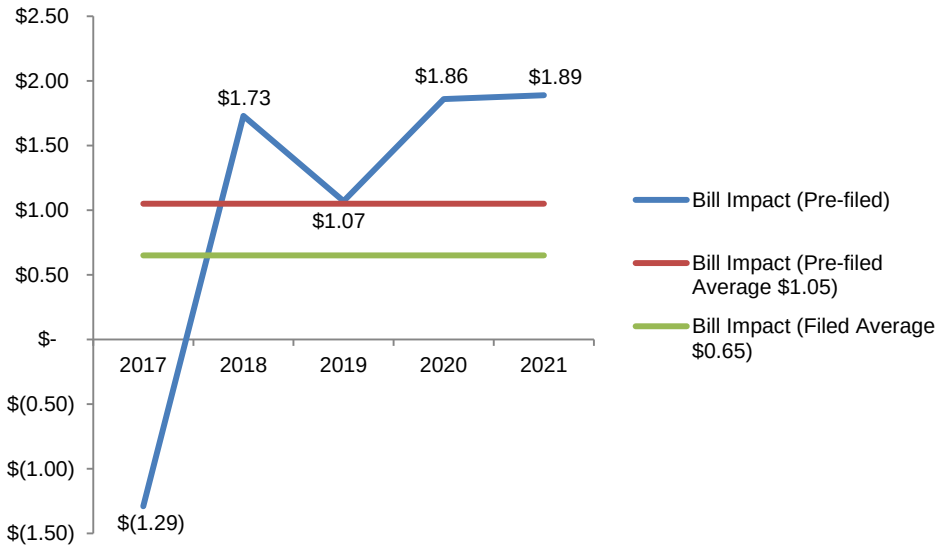
Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q3 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

Rate-Smoothing Proposal:

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents ~~per month per year~~

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister requesting authority for OPG to approve international travel for its employees
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- OPG has indicated that international travel is integral to the safe and prudent operation of its business and that special status will enable efficient decision-making while lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected to see increases
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

From:	Bruno Amara
To:	Ronald Kwan; John Kim
Cc:	Francisco Chinchon; Adam Prokop
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 1:52:30 PM
Attachments:	2017 04 11 OPG Business Plan Review v7_Markup6.pptx

I found 2nd bullet slide 9 convoluted. See edit. But nevermind if it's too much editing.

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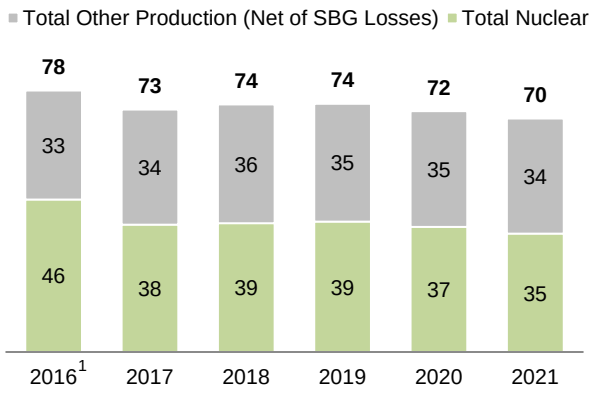
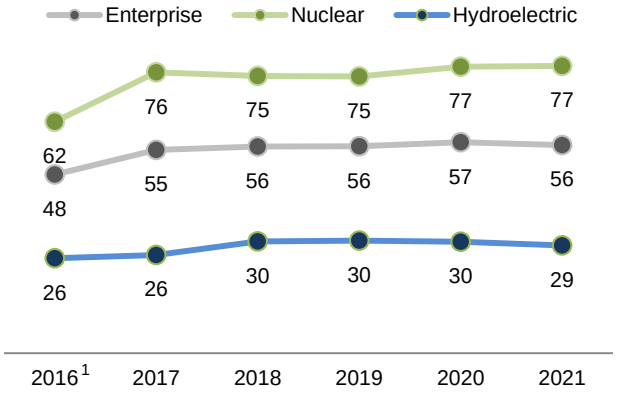


Total Generating Cost ($/MWh)



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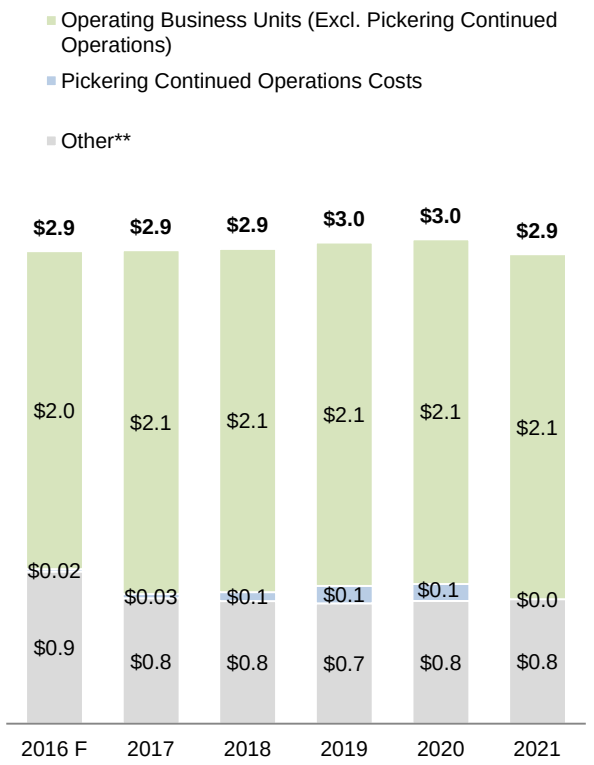

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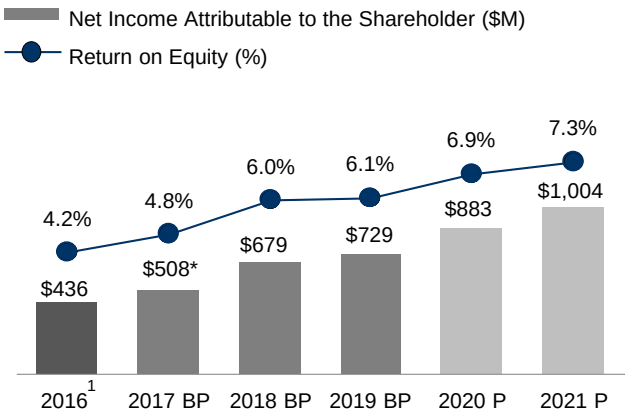

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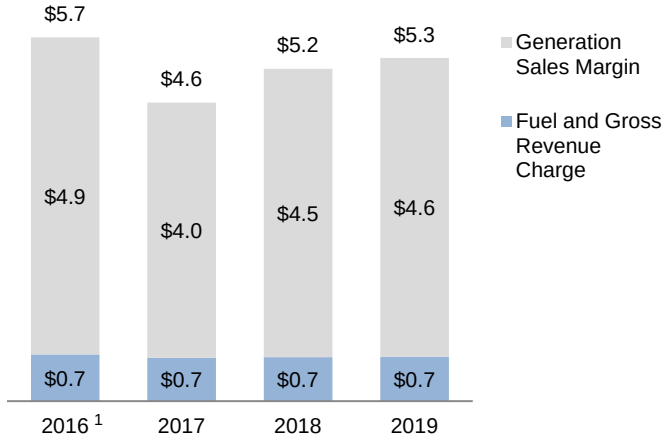

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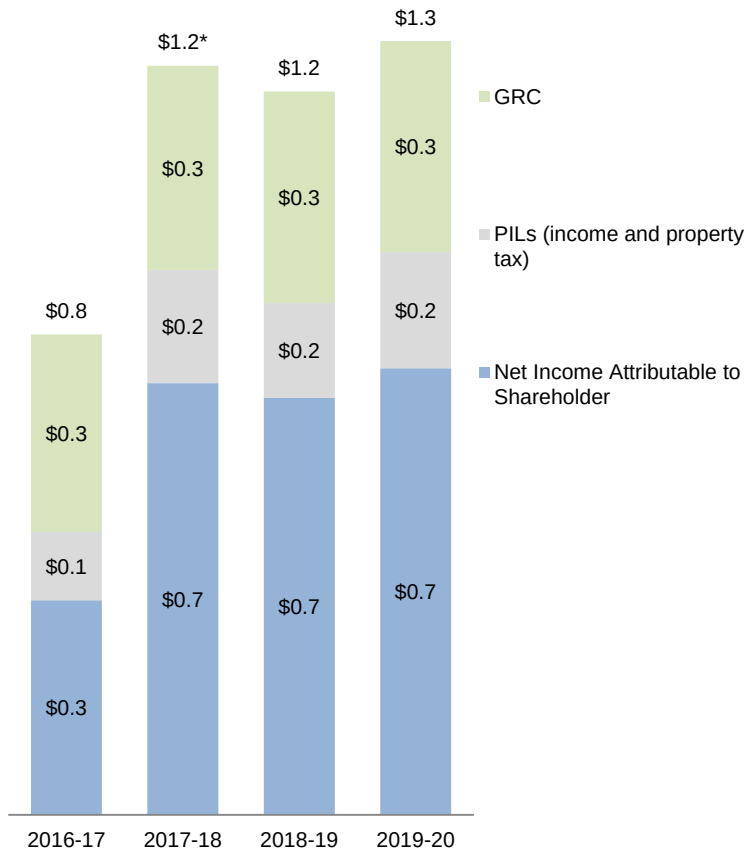

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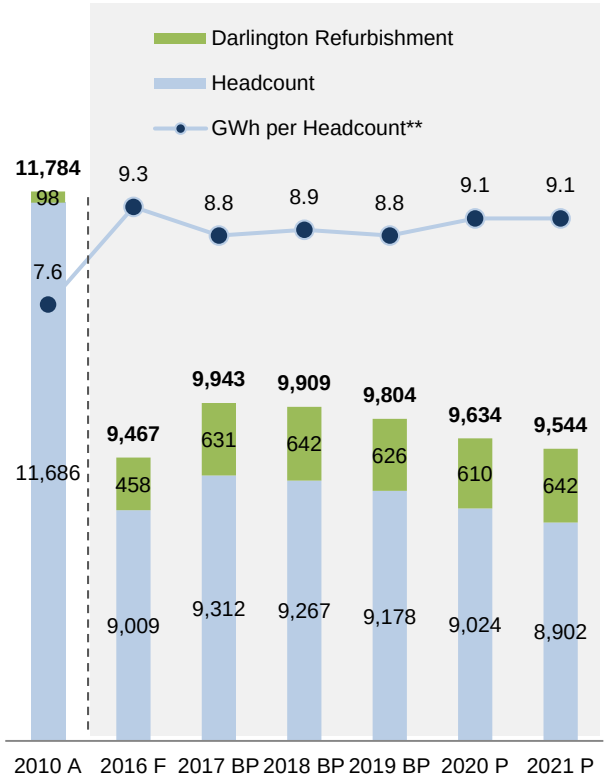

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1. Business Plan Overview

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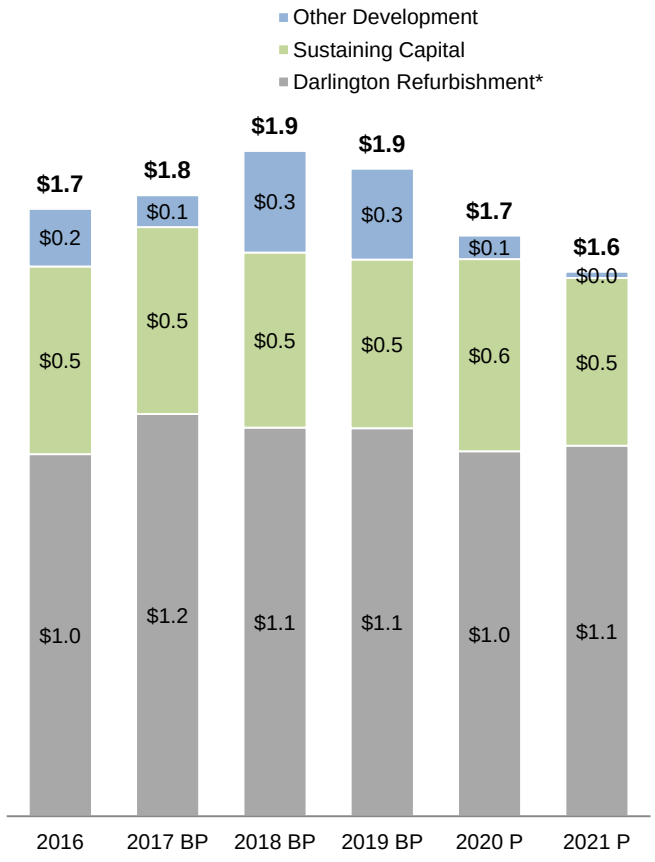

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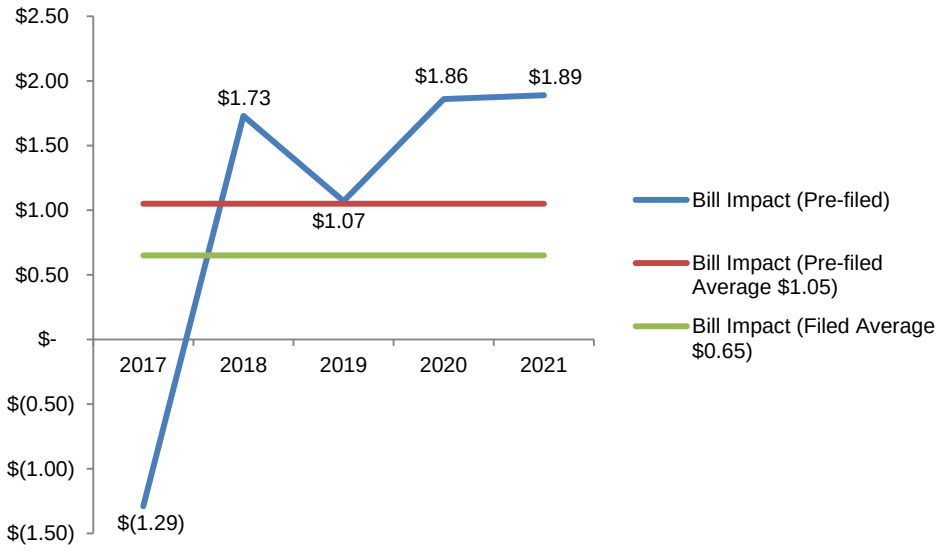

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  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

From: Francisco Chinchon
To: Ronald Kwan; John Kim
Cc: Bruno Amara
Subject: RE: OPG BP concurrence - Energy materials
Date: Monday, April 24, 2017 1:11:00 PM
Attachments: 2017 03 14 OPG concurrence letter v6_markup3.docx

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Hi,

I'm okay with the edits Ron made and just tweaked a thing. I also added a bit more to the comments.

Thanks,

Francisco

From: Ronald Kwan
Sent: Monday, April 24, 2017 1:07 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hi John,

Some suggestions.

I think we should explain the ONFA-related edits. I suggested some comments, which SIFB may want to review.

Ron

From: John Kim
Sent: April-24-17 11:46
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: OPG BP concurrence - Energy materials

Hi Ron,

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They have a meeting with Serge at 3:30 so would appreciate any comments soon.

John

Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority
Ph: 416-212-6996
Email: john.kim@ofina.on.ca

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with financial targets and the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing subsequent unit refurbishments after Unit 2 is successfully returned to service.

We continue to support the planned operation of Pickering units up to 2024 as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to seek concurrence to proceed with ongoing Pickering operation after the necessary regulatory approvals are complete.

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities ~~costs to consumers~~ for future decommissioning and long-term management of waste from Ontario's nuclear fleet. ~~plants. In addition, the segregated nuclear funds set aside under ONFA have reached fully funded status.~~ With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations [and related segregated funds] in a prudent manner~~, the decision to fund these costs now provides security for future generations of Ontarians~~.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan.

Commented [RK1]: Recommended not to use this wording, particularly also using the fully-funded wording that follows.

Under ONFA, for prudence, the Province required OPG to accelerate contributions to the funds, in advance of collecting the amounts from ratepayers. Even if the funds are currently estimated to be fully-funded, OPG (and the Province as Shareholder) still needs to recover its nuclear liabilities costs in rates.

Commented [RK2]: If wording is retained, should be reworded.

"As a result of the lower estimated liabilities and recent financial market performance, the segregated nuclear funds set aside under ONFA are currently estimated to be fully funded."

Commented [FC3R2]: Should be noted that the funds are fully funded today but changes in market conditions could put the funds in a temporary deficit position in a very short period.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Ali Ghiassi, Chief of Staff, Ministry of Finance
Scott Thompson, Deputy Minister, Ministry of Finance
Serge Imbrogno, Deputy Minister, Ministry of Energy

Commented [RK4]: Only add in if Energy CoS is included.

From:	John Kim
To:	Ronald Kwan
Cc:	Francisco Chinchon; Bruno Amara; Adam Prokop
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 12:17:06 PM
Attachments:	2017 04 11 OPG Business Plan Review v7_Markup4.pptx

Here's the deck….we'd delete most, if not all, of the comments.

Thanks,

John

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Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
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Ontario

MINISTRY OF
ENERGY

OPG Business Plan

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

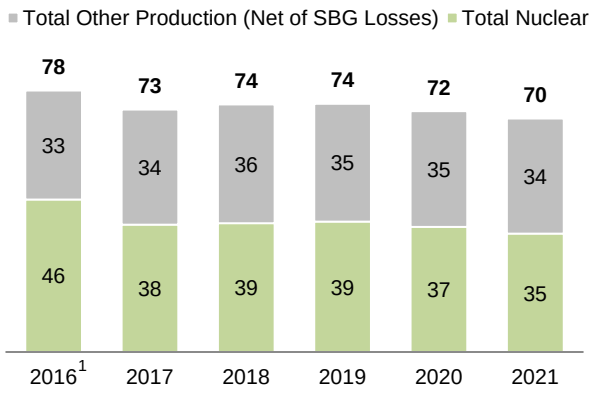
  - In addition, the Province's net debt position should remain unchanged

1. Business Plan Overview

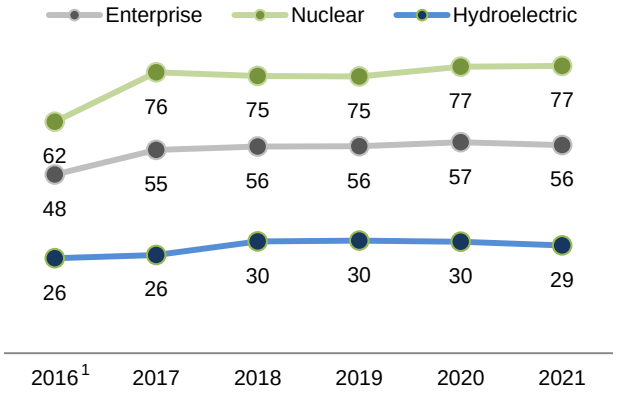
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 78.2 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Also includes a partial overlap starting in 2021 between second and third unit refurbishments
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

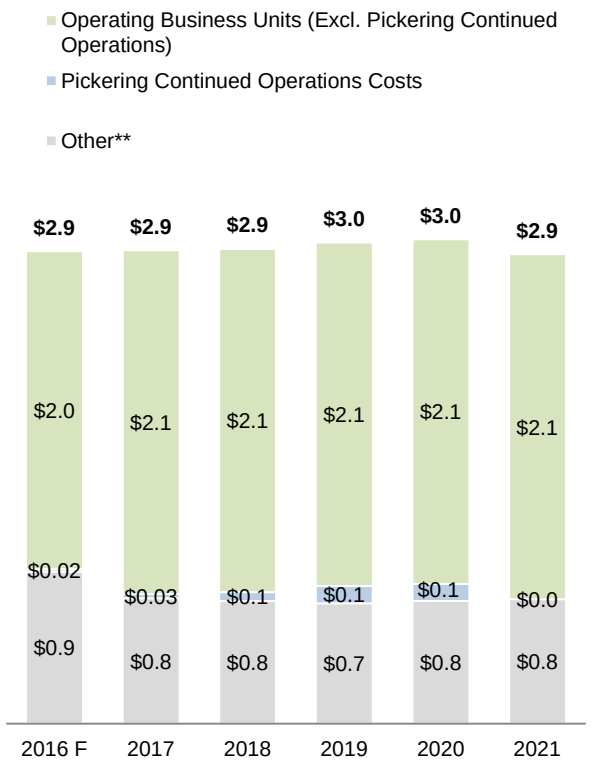
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

1. Business Plan Overview

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
  - Incremental outage and other program costs to enable Pickering continued operations
  - Partially offset by declining pension and OPEB costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



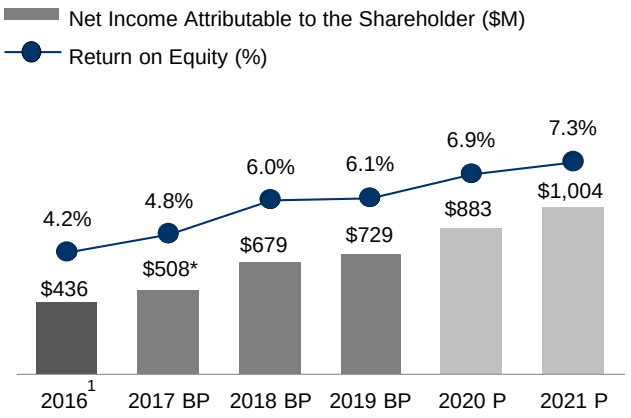
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs and support services

1. Business Plan Overview

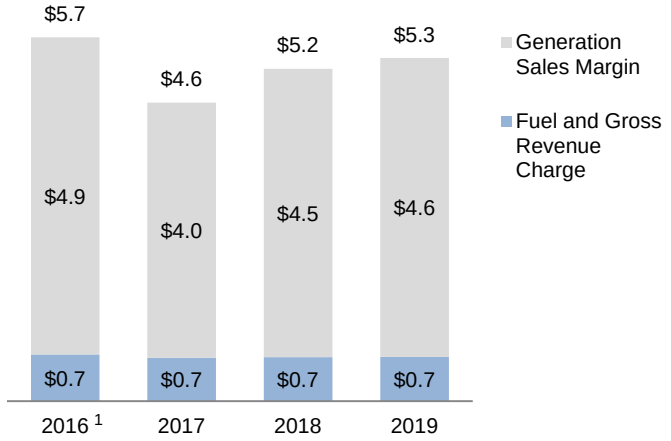
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
  - 2017 net income is forecast to increase as a result of new regulated rates, a gain on sale of OPG's head office, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
  - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from oncoming stations, including Nanticoke solar in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return

Net Income ($M) and ROE (%)



Revenue Margin ($B)



*Includes extraordinary gain associated with the sale of OPG head office

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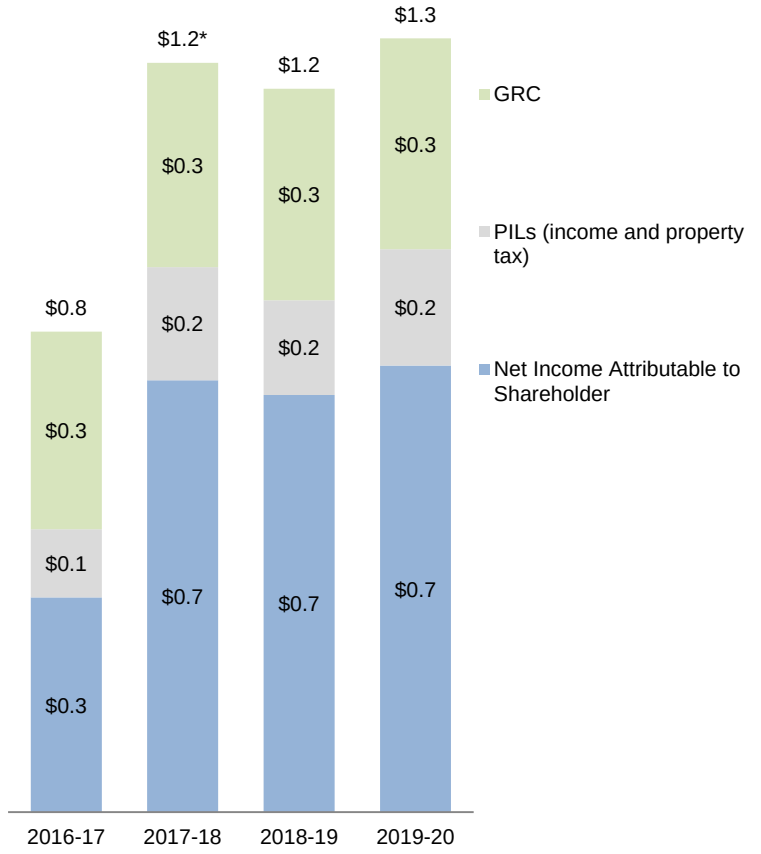
1. Business Plan Overview

d) Shareholder Return

- Total return to the shareholder averages ~$1B over the period
- Total return to the shareholder improves over the period largely due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs) while income tax PILs are consolidated by the Ontario Electricity Financial Corporation (OEFC)
- OPG also pays a Gross Revenue Charge (GRC) and Property Taxes to the OEFC

Total Shareholder Return ($B)



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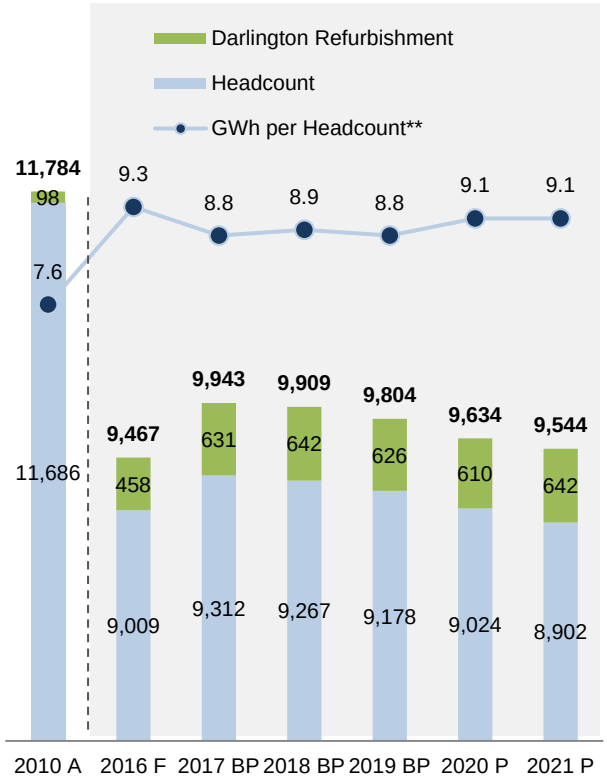

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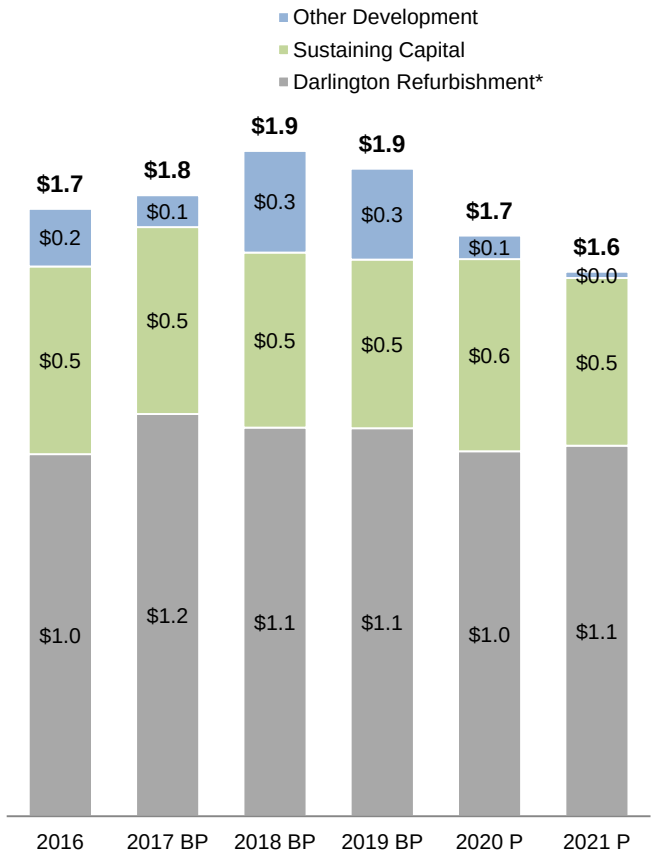

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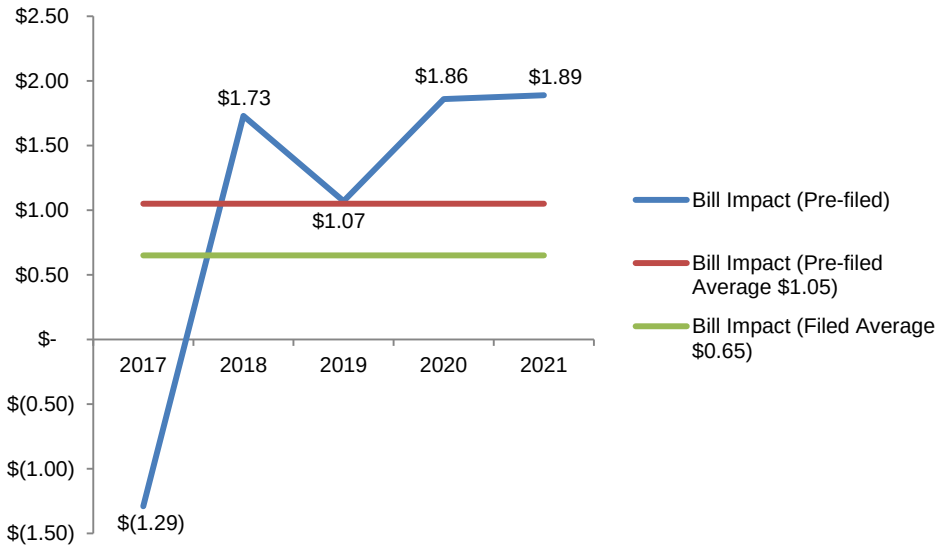

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Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
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Receivables from related parties	0.4
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Total current assets	**$1.7**
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From:	John Kim
To:	Bruno Amara; Ronald Kwan
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 2:16:49 PM
Attachments:	2017 04 11 OPG Business Plan Review v7_Markup7.pptx

I know this is just house-keeping but I also made changes to the last bullet on slide 6.

I think it meant to say that a portion of the GRC is paid to the Province's CRF.

From: Bruno Amara
Sent: Monday, April 24, 2017 2:06 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hmm? Yes, maybe I made one edit too many. I think the first part is indeed OK. Maybe just the last edit "per month per year" I think is already implied.

From: Ronald Kwan
Sent: Monday, April 24, 2017 1:55 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hi Bruno,

That seems to change the meaning. Is that right?

Ron

From: Bruno Amara
Sent: April-24-17 13:52
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

I found 2nd bullet slide 9 convoluted. See edit. But nevermind if it's too much editing.

From: Ronald Kwan
Sent: Monday, April 24, 2017 12:53 PM
To: John Kim <John.Kim@ofina.on.ca>

Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Hi John,

I had some edits, primarily to slide 6, which I regard as important to recast.

Ron

From: John Kim
Sent: April-24-17 12:17
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Here's the deck….we'd delete most, if not all, of the comments.

Thanks,

John

From: John Kim
Sent: Monday, April 24, 2017 11:46 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: OPG BP concurrence - Energy materials

Hi Ron,

Pls. see attached with proposed edits from SIFB to the concurrence letter. We are still looking at the deck and will be forthcoming soon.

They have a meeting with Serge at 3:30 so would appreciate any comments soon.

John

Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority
Ph: 416-212-6996
Email: john.kim@ofina.on.ca

Ontario

MINISTRY OF
ENERGY

OPG Business Plan

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

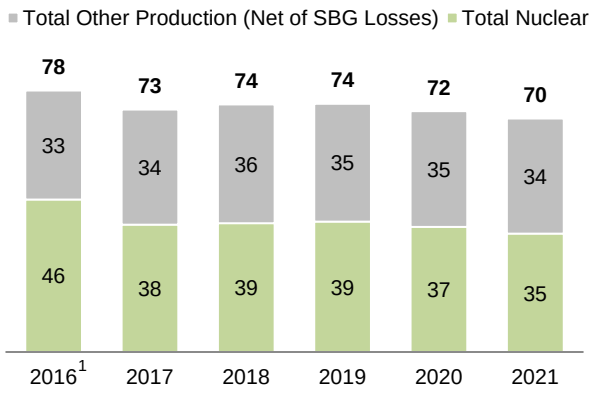
  - In addition, the Province's net debt position should remain unchanged

1. Business Plan Overview

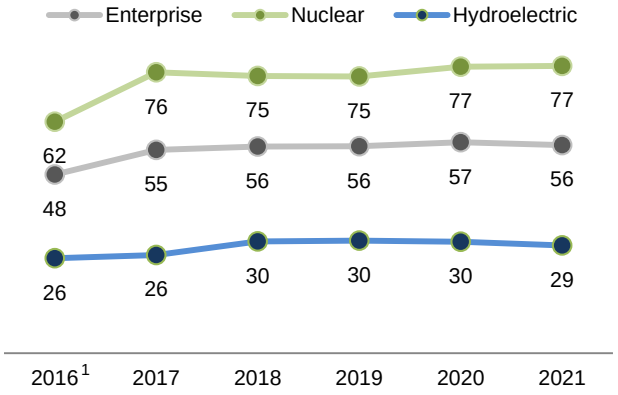
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 78.2 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Also includes a partial overlap starting in 2021 between second and third unit refurbishments
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

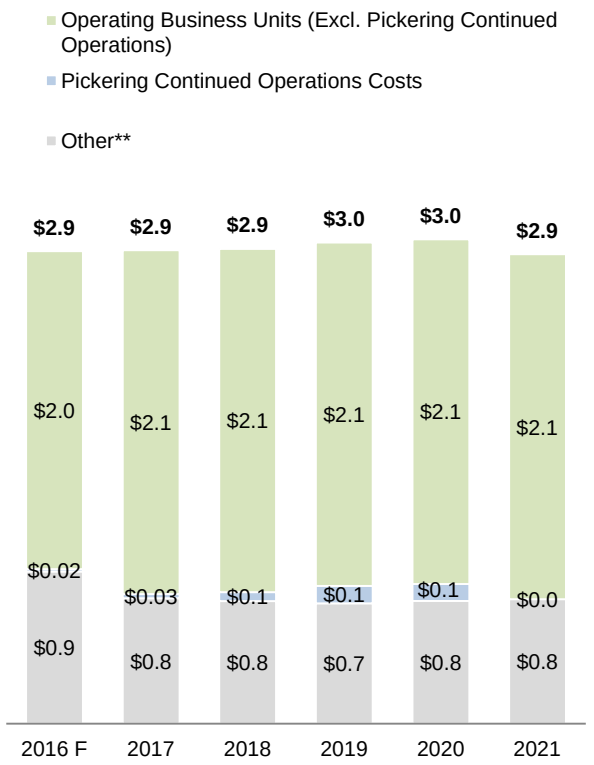
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

1. Business Plan Overview

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
  - Incremental outage and other program costs to enable Pickering continued operations
  - Partially offset by declining pension and OPEB costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



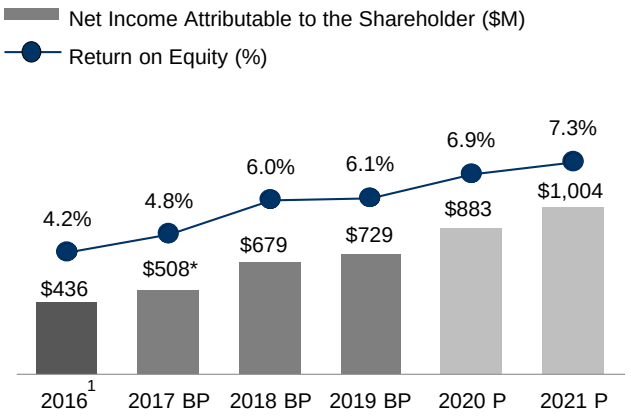
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs and support services

1. Business Plan Overview

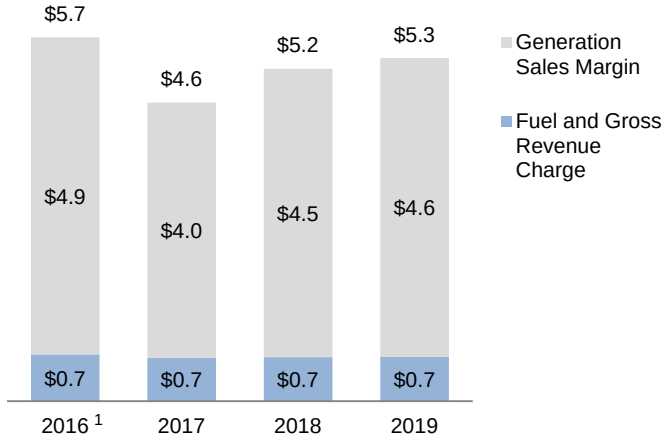
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
  - 2017 net income is forecast to increase as a result of new regulated rates, a gain on sale of OPG's head office, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
  - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from oncoming stations, including Nanticoke solar in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return

Net Income ($M) and ROE (%)



Revenue Margin ($B)



*Includes extraordinary gain associated with the sale of OPG head office

1. Actuals

1. Business Plan Overview

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG.

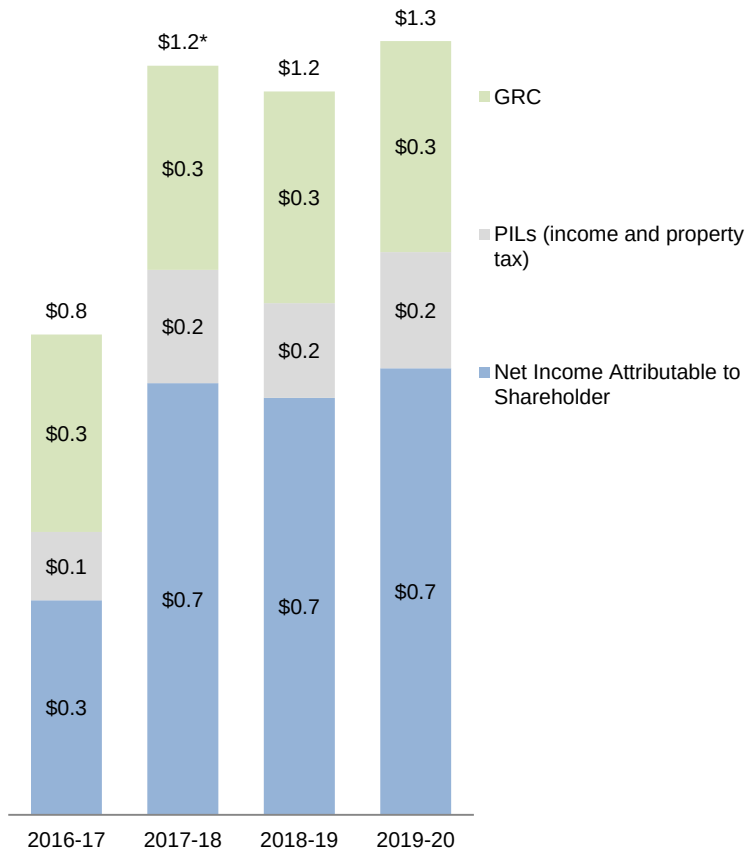
- ~~Total r~~Return to the shareholder improves ~~over the period largely~~ due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies

- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)

- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to ~~are consolidated by~~ the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue

- OPG also pays a portion of the Gross Revenue Charge (GRC) ~~and Property Taxes to the OEFC~~ to the Province's Consolidated Revenue Fund

Total Fiscal Revenues ~~Shareholder Return~~ ($B)



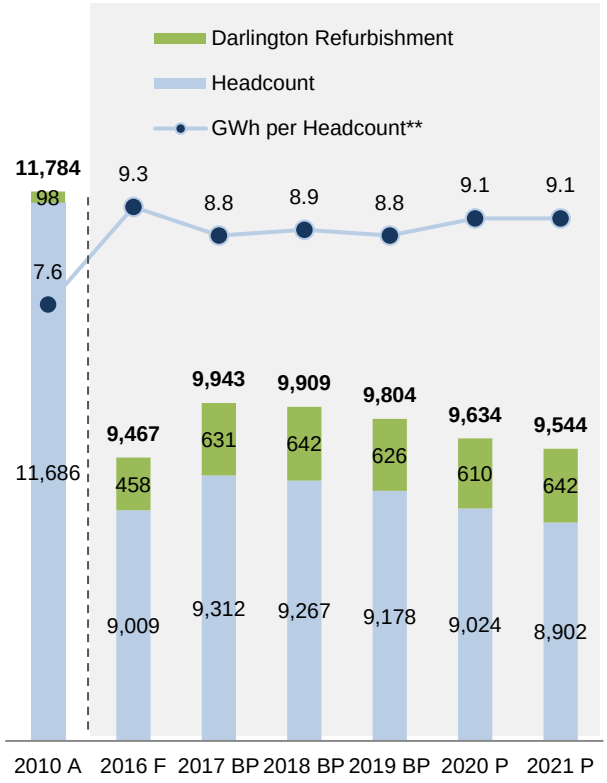
*Includes gain associated with the sale of OPG head office

1. Business Plan Overview

e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG has saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~60 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations

Ongoing Operations Regular Headcount and Productivity



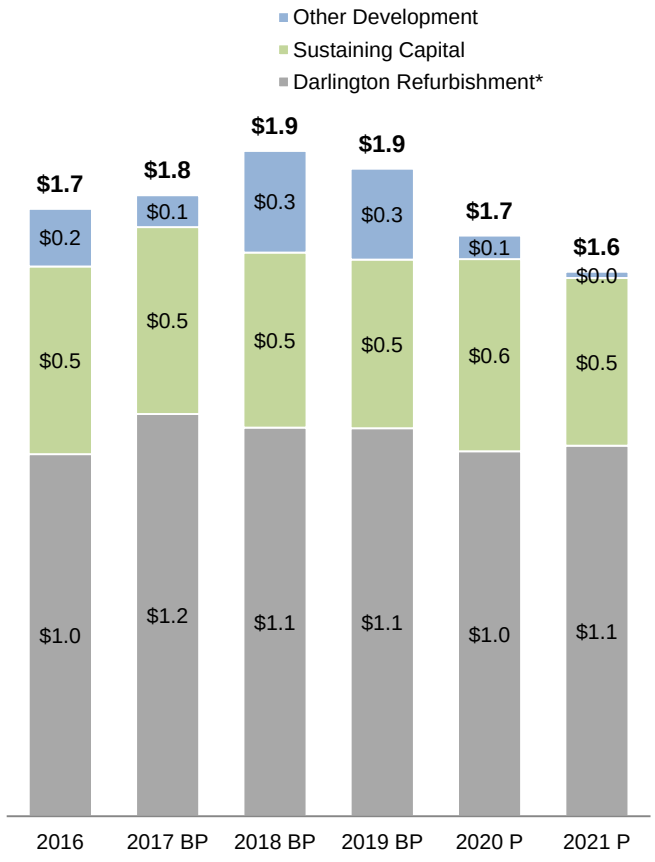
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

1. Business Plan Overview

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew II
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Developments:** Investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

2. Other Considerations

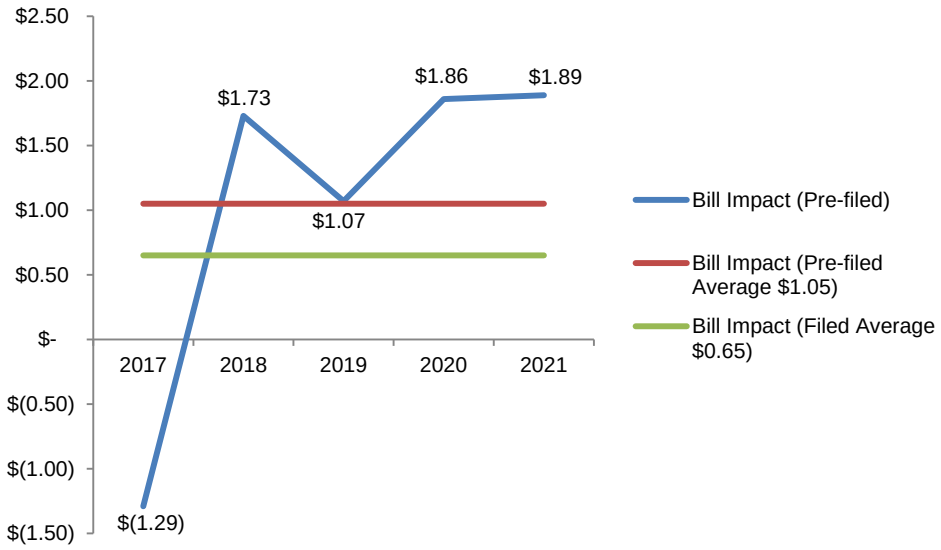
Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q3 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

Rate-Smoothing Proposal:

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents ~~per month per year~~

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister requesting authority for OPG to approve international travel for its employees
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- OPG has indicated that international travel is integral to the safe and prudent operation of its business and that special status will enable efficient decision-making while lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected to see increases
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
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From:	Gadi Mayman
To:	Ronald Kwan; Ken Kandeepan; Mike Manning
Cc:	Anna Strathy; Gavin He
Subject:	Re: GA Financing Response to Minister"s Request
Date:	Tuesday, April 18, 2017 10:53:43 AM

I didn't. I'll ask Serge and Steen for a copy.

From: Ronald Kwan
Sent: Tuesday, April 18, 2017 10:44 AM
To: Gadi Mayman; Ken Kandeepan; Mike Manning
Cc: Anna Strathy; Gavin He
Subject: RE: GA Financing Response to Minister's Request

Hi Gadi,

Did we get the final copy of the Energy letter to OPG?

Ron

From: Gadi Mayman
Sent: April-18-17 9:36 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>
Cc: Anna Strathy <Anna.Strathy@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: Fw: GA Financing Response to Minister's Request

The OFA isn't mentioned in the body of the letter, but given that I'm cc'd with a pretty esteemed list, I'll take that as sufficient.

From: LORD Bernard -BOARDCHAIR <bernard.lord@opg.com>
Sent: Tuesday, April 18, 2017 9:10 AM
To: 'glenn.thibeault@ontario.ca'
Cc: Charles Sousa (MOF); Scott Thompson (CAB); Serge Imbrogno (ENERGY); Gadi Mayman; LYASH Jeffrey -PRESIDENT; HARTWICK Ken -FINANCE; GINTHER Chris -CAO; KING Catriona -OFFCORPSEC; MATHIAS Carlton -OFFCORPSEC
Subject: GA Financing Response to Minister's Request

Hello,

Please see the attached letter from Bernard Lord, Board Chair Ontario Power Generation.

Thanks,

Rosemarie

Rosemarie Hoilett
Executive Assistant - Jeff Lyash President & CEO | Bernard Lord Board Chair

Ontario Power Generation
700 University Ave | H19-A24
Toronto ON M5G 1X6
416-592-2114 | rosemarie.hoilett@opg.com

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