SECTION 3:
BACKGROUND

This is the fourth general rate setting proceeding before the Board for OPG. Below is a brief synopsis of the prior three proceedings, as well as the Board's findings in EB-2009-0084, the "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities."

EB-2007-0905

EB-2007-0905 was OPG's first cost of service application before the Board, including cost of capital and capital structure. In its November 3, 2008 decision in EB-2007-0905, the Board laid out the legislative requirements regarding rate regulation of OPG and reached numerous conclusions regarding its approach to setting rates for OPG.

With regard to the capital structure, the Board stated: "The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[4] The Board further concluded that it would apply the stand-alone principle in establishing the capital structure for the Company, noting that "[t]he stand-alone principle is a long-established regulatory principle,"[5] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[6] The Board determined that a 47% equity ratio was appropriate for the Company, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.[7]

During EB-2007-0905, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the two businesses was an approach worth examining at the next proceeding.

At the time of EB-2007-0905, OPG owned and operated six prescribed hydroelectric generating stations (Sir Adam Beck I and II, Sir Adam Beck Pump Generating Station, DeCew Falls I and II, and R.H. Saunders), and three prescribed nuclear generating stations (Pickering A, Pickering B, and Darlington).

EB-2009-0084

In EB-2009-0084, the Board reviewed its cost of capital policies for Ontario's regulated utilities to determine whether the automatic adjustment formula was continuing to meet the fair return standard. As a result of its consultative process, the Board affirmed its view that the fair return standard frames the discretion of a regulator, by setting out three standards or requirements (comparable investment, financial integrity, and capital attraction) that must be satisfied by the cost of capital determinations.[8] The Board observed that meeting the fair return standard is not optional; it is a legal requirement.

4 EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.
5 *Ibid*, at 140.
6 *Ibid*, at 142.
7 *Ibid*, at 149-150.
8 EB-2009-0084, Report of the Board, December 11, 2009, at i.

OPG, as a corporation, has a split "A (low)" issuer and unsecured debt rating (as of April 25, 2016) from DBRS, and a "BBB+" corporate credit rating (as of July 7, 2015) from S&P. Both ratings agencies point to support provided by the Province, a strong market position, and a supportive regulatory framework as credit positive factors, while considering the Company's capital expenditure plan coupled with already weak credit metrics to be a credit risk.

DBRS further specifically cites nuclear generation risk as being a "challenge" for OPG. In addition, S&P notes that it rates OPG as "BBB-" (*i.e.*, two notches below its "BBB+" corporate credit rating) on a stand-alone basis, before consideration of support by the Province. This is an important point with regard to OPG, as its evaluated operations are regulated by the OEB on a stand-alone basis.

HYDROELECTRIC FACILITIES

As noted earlier, OPG has 54 hydroelectric stations that are subject to OEB regulation, which supply approximately 6,425 MW of generating capacity. OPG's hydroelectric stations vary in size, location, age, operating and hydrological characteristics (*i.e.*, base load, intermediate, peaking). The hydroelectric system thus represents a diverse set of assets. Because of the geographic diversity of the system, the hydroelectric assets are subject to numerous Federal, interprovincial, and provincial regulations, treaties, agreements, and waterpower leases.

Generally, the major risks to a regulated utility related to hydropower include: (1) the ability to license and gain permits and/or water power leases for new facilities; (2) availability of water to power the stations; (3) water management plans, including environmental and water level regulations that affect the way the stations operate or impede the license to operate; (4) the need for capital expenditures to address regulatory and sustaining requirements (*e.g.*, dam safety); and (5) the ability to recover costs, including a return, in a timely manner.

OPG's hydroelectric business is expected to be relatively stable from an operating risk perspective relative to recent experience and conditions as they existed at the time of EB-2013-0321, as discussed further below. As discussed in the section following, business risks related to the hydroelectric rate setting mechanism are expected to increase relative to EB-2013-0321.

OPG's hydroelectric system is a mature system (the average age of OPG's hydroelectric system is 78 years). This means that, while the risk of equipment failure is higher, the risk of discovering new operational issues or the intervention of new stakeholders is lower than it would be for a newer system. In addition, Concentric understands that, while OPG has planned capital project expenditures totaling approximately $1 billion over the 2017-2021 period, OPG is not planning to add any significant amount of new hydroelectric capacity during that period. Because of this, OPG's need to obtain new water power leases or rights would not materially deviate from recent experience, leaving associated risks at similar levels as those faced at the time of EB-2013-0321.

OPG is subject to variances in water flow and surplus baseload generation curtailments.[28] However, while the availability of water to power the stations can vary significantly from year to year (for instance, hydroelectric production by OPG was approximately five terawatt-hours less in 2010 than

28 Surplus baseload generation occurs when production from baseload generation facilities exceeds demand as determined by the Independent Electricity System Operator ("IESO"). In recognition of the significance of surplus baseload generation to OPG's financial results, the Board approved a Surplus Baseload Generation Variance Account in EB-2010-0008.

Bill 135, Energy Statute Law Amendment Act, 2016

Chiarelli, Hon Bob *Minister of Energy*

Current Status: Royal Assent received Chapter Number: S.O. 2016 C.10

View the Bill

Bill 135 2016

An Act to amend several statutes and revoke several regulations in relation to energy conservation and long-term energy planning

CONTENTS

Her Majesty, by and with the advice and consent of the Legislative Assembly of the Province of Ontario, enacts as follows:

Contents of this Act

1. This Act consists of this section, sections 2 and 3, and the Schedules to this Act.

Commencement

2. (1) Subject to subsections (2) and (3), this Act comes into force on the day it receives Royal Assent.

Same, Schedules

(2) The Schedules to this Act come into force as provided in each Schedule.

Different dates for same Schedule

(3) If a Schedule to this Act or any portion of a Schedule to this Act provides that it is to come into force on a day to be named by proclamation of the Lieutenant Governor, the proclamation may apply to the whole or any portion of the Schedule, and proclamations may be issued at different times as to any portion of the Schedule.

Short title

3. The short title of this Act is the Energy Statute Law Amendment Act, 2016.

Schedule 1

Amendments to the Green Energy Act, 2009

1. Sections 6 and 7 of the Green Energy Act, 2009 are repealed and the following substituted:

Public agency, energy conservation and demand management plan

6. (1) The Lieutenant Governor in Council may, by regulation, require a public agency to prepare and submit to the Ministry an energy conservation and demand management plan.

Requirements

(2) The energy conservation and demand management plan must comply with any prescribed requirements and must include the following information:

1. A summary of annual energy consumption for each of the public agency's prescribed operations.
2. A description and a forecast of the expected results of current and proposed activities and measures to conserve the energy consumed by the public agency's prescribed operations and to otherwise reduce the amount of energy consumed by the public agency, including by employing such energy conservation and demand management methods as may be prescribed.
3. A summary of the progress and achievements in energy conservation and other reductions described in paragraph 2 since the previous plan.
4. Such additional information as may be prescribed.

Specified targets and standards, public agencies

(3) The Lieutenant Governor in Council may, by regulation, require a public agency to achieve prescribed targets and meet prescribed energy and environmental standards, including standards for energy conservation and demand management.

Implementation and publication

(4) The public agency shall,

(a) implement the energy conservation and demand management plan and comply with any prescribed requirements respecting the implementation of the plan; and

(b) publish the plan in accordance with any prescribed requirements.

Joint plans

(5) Two or more public agencies may prepare a joint energy conservation and demand management plan and may publish and implement it jointly.

Effect

(6) If the joint plan satisfies the requirements established under this section, the public agencies are not required to prepare, publish and implement separate energy conservation and demand management plans for the same period.

Prescribed person, reporting of energy consumption and water use

7. (1) The Lieutenant Governor in Council may, by regulation,

(a) require a prescribed person, other than a public agency, to report to the Ministry, in the prescribed manner, energy consumption, water use, ratings or other performance metrics in respect of energy consumption and water use and such additional information as may be prescribed in respect of each of the person's prescribed properties;

(b) prescribe circumstances in which the Minister may request that a person mentioned in clause (a) undertake verification, in the prescribed manner, of any information required to be reported under a regulation made under clause (a) or under a notice published under subsection (4); and

(c) require a person mentioned in clause (a) to comply with a request by the Minister under clause (b).

Manner of reporting

(2) For the purposes of clause (1) (a), the regulations may require reporting through the use of a prescribed reporting system, including an electronic reporting system administered by a third party and a reporting system that generates ratings or other performance metrics in respect of energy consumption and water use.

Verification by prescribed person

(3) For the purposes of clause (1) (b), the regulations may specify that the verification must be conducted by a prescribed person.

Minister's notice, additional requirements

(4) The Minister may, by publishing notice in the registry under the Environmental Bill of Rights, 1993, require a prescribed person under clause (1) (a) to report to the Ministry, in the prescribed manner, energy consumption, water use, ratings or other performance metrics in respect of energy consumption and water use and any additional information in respect of each of the person's prescribed properties.

Same

(5) A notice published under subsection (4) may incorporate another document by reference and may provide that the reference to the document includes amendments made to the document from time to time after the notice is published.

Prescribed person, energy conservation and demand management plan

7.1 (1) The Lieutenant Governor in Council may, by regulation, require a prescribed person to prepare and submit to the Ministry an energy conservation and demand management plan.

Same

(2) A regulation under subsection (1) may require that the person,

(a) prepare the plan in prescribed circumstances and in accordance with prescribed requirements; and

(b) make the plan available to the public in accordance with prescribed requirements.

Minister may publish information

7.2 (1) Despite any other Act, the Minister may,

(a) make available to the public any of the information required to be reported or submitted to the Ministry under sections 7 and 7.1; and

(b) share any of the information required to be reported or submitted to the Ministry under sections 7 and 7.1 with another Ministry or agency of the Government of Ontario, or such other persons or entities as may be prescribed for the purposes of this section.

Information supplied in confidence

(2) If the Minister has not made information available to the public under clause (1) (a), the information is deemed, for the purposes of section 17 of the Freedom of Information and Protection of Privacy Act, to have been supplied in confidence to the Minister.

Distributors, requirement to provide information

Definition

7.3 (1) In this section,

"distributor" means,

(a) a distributor within the meaning of section 3 of the Ontario Energy Board Act, 1998,

(b) a gas distributor within the meaning of section 3 of the Ontario Energy Board Act, 1998, or

(c) an owner or operator of a water works within the meaning of subsection 1 (1) of the Ontario Water Resources Act.

Information to be provided

(2) A distributor that has been prescribed for the purposes of this section shall, upon receiving a request from a person who is required to report under section 7 or to prepare a plan under section 7.1 in respect of a property that meets prescribed criteria, make available to that person, in the prescribed manner, prescribed information with respect to the consumption or use of electricity, gas or water distributed by the distributor to the property.

Same

(3) The requirements in subsection (2) are subject to any prescribed conditions.

2. The heading to Part III of the Act is amended by adding "AND EFFICIENT USE OF WATER" at the end.

3. Subsection 16 (2) of the Act is amended by adding the following clauses:

(b.1) governing everything required under or provided for in or that may be prescribed under sections 6, 7 and 7.1, including,

(i) the periods that may be covered by plans and reports required under those sections and the intervals for which the plans and reports are required,

(ii) the submission of the plans, reports and other documents to the Ministry,

(iii) circumstances in which two or more buildings or structures may be treated as a single property for the purposes of clause 7 (1) (a),

(iv) generally governing how those sections are to be complied with;

(b.2) governing circumstances in which two or more buildings or structures may be treated as a single property for the purposes of section 7.3;

. . . . .

(d.1) prescribing water efficiency standards or requirements for appliances or products that consume energy and are prescribed under clause (c);

Commencement

4. This Schedule comes into force on the day the Energy Statute Law Amendment Act, 2016 receives Royal Assent.

Schedule 2

Amendments to the Electricity act, 1998 and the Ontario Energy Board act, 1998

Electricity Act, 1998

1. Section 1 of the Electricity Act, 1998 is amended by adding the following clause:

(a.1) to establish a mechanism for energy planning;

2. (1) The definition of "procurement contract" in subsection 2 (1) of the Act is repealed and the following substituted:

"procurement contract" means a contract entered into by the IESO pursuant to section 25.32, including pursuant to a directive issued under subsection 25.32 (5) or a direction issued under subsection 25.32 (7) or (8); ("contrat d'acquisition")

(2) Subsection 2 (1.5) of the Act is repealed and the following substituted:

Procurement contracts, transition

(1.5) For the purposes of this Act, a procurement contract is deemed to include,

(a) a contract entered into or assumed, pursuant to section 25.32, before the day section 7 of Schedule 2 to the Energy Statute Law Amendment Act, 2016 comes into force; and

(b) a contract entered into, pursuant to section 25.35, before its repeal by section 8 of Schedule 2 to the Energy Statute Law Amendment Act, 2016.

3. Clause 6 (1) (h) of the Act is amended by adding "electricity storage, transmission systems or any part of such systems" after "electricity capacity".

4. (1) Subparagraph 2 i of subsection 9 (4) of the Act is repealed and the following substituted:

i. electricity supply, capacity or storage,

(2) Paragraph 2 of subsection 9 (4) of the Act is amended by striking out "or" at the end of subparagraph iii, by adding "or" at the end of subparagraph iv and by adding the following subparagraph:

v. transmission systems or any part of such systems.

(3) The definition of "microFIT program" in subsection 9 (6) of the Act is amended by striking out "that is authorized by a direction issued to the IESO under section 25.35" and substituting "that is continued under subsection 25.32 (10)".

5. Subsection 25.4 (1) of the Act is amended by adding "and shall, if required by the Minister to do so, examine, report and advise on any question respecting electricity" at the end.

6. The heading to Part II.2 of the Act is repealed and the following substituted:

Part II.2

Planning, Procurement and Pricing

7. Sections 25.29, 25.30, 25.31 and 25.32 of the Act are repealed and the following substituted:

Long-term energy plans

25.29 (1) At least once during each period prescribed by the regulations, the Minister shall, subject to the approval of the Lieutenant Governor in Council, issue a long-term energy plan setting out and balancing the Government of Ontario's goals and objectives respecting energy for the period specified by the plan.

Same

(2) For the purposes of subsection (1), a long-term energy plan may include goals and objectives respecting,

(a) the cost-effectiveness of energy supply and capacity, transmission and distribution;

(b) the reliability of energy supply and capacity, transmission and distribution, including resiliency to the effects of climate change;

(c) the prioritization of measures related to the conservation of energy or the management of energy demand;

(d) the use of cleaner energy sources and innovative and emerging technologies;

(e) air emissions from the energy sector, taking into account any projections respecting the emission of greenhouse gases developed with the assistance of the IESO;

(f) consultation with aboriginal peoples and their participation in the energy sector, and the engagement of interested persons, groups and communities in the energy sector; and

(g) any other related matter the Minister determines should be addressed.

Technical reports by IESO

(3) The Minister shall, before issuing a long-term energy plan under subsection (1), require the IESO to submit a technical report on the adequacy and reliability of electricity resources with respect to anticipated electricity supply, capacity, storage, reliability and demand and on any other related matters the Minister may specify, and the Minister shall,

(a) consider the report in developing the long-term energy plan; and

(b) post the report on a publicly-accessible Government of Ontario website or publish it in another manner, before undertaking any consultations under subsection (4).

Consultation required

(4) The Minister shall, before issuing a long-term energy plan under subsection (1), consult with any consumers, distributors, generators, transmitters, aboriginal peoples or other persons or groups that the Minister considers appropriate given the matters being addressed by the long-term energy plan, and the Minister shall consider the results of such consultation in developing the long-term energy plan.

Notice

(5) The Minister shall publish notice of consultations under subsection (4), together with any relevant background materials or other information the Minister considers appropriate, in the environmental registry established under section 5 of the Environmental Bill of Rights, 1993.

Participation

(6) The Minister shall take steps to promote the participation of the persons or groups with whom the Minister intends to consult under subsection (4), including,

(a) scheduling one or more consultation meetings, where the Minister considers it appropriate to do so, that the persons or groups are entitled to attend in person; and

(b) providing for the participation of persons or groups in consultations through electronic or other means not requiring personal attendance.

Publication

(7) On issuing a long-term energy plan under subsection (1), the Minister shall post it on a publicly-accessible Government of Ontario website or publish it in another manner, and shall also post or publish any other information, such as key data and cost projections, used in the development of the long-term energy plan that the Minister determines should be made publicly available.

Implementation directives

To the IESO

25.30 (1) The Minister may, subject to the approval of the Lieutenant Governor in Council, issue a directive to the IESO setting out the Government of Ontario's requirements respecting the implementation of the long-term energy plan by the IESO and any other related requirements, and the date by which the IESO must submit an implementation plan to the Minister under subsection 25.31 (1).

To the Board

(2) The Minister may, subject to the approval of the Lieutenant Governor in Council, issue a directive to the Board setting out the Government of Ontario's requirements respecting the implementation of the long-term energy plan in respect of matters falling within the Board's jurisdiction, and the date by which the Board must submit an implementation plan to the Minister under subsection 25.31 (2).

Amendments

(3) The Minister may, subject to the approval of the Lieutenant Governor in Council, issue an amendment to a directive issued under subsection (1) or (2).

Same

(4) An amendment issued under subsection (3) may change or remove requirements or set out new requirements, and shall specify the date by which the IESO or the Board, as the case may be, must submit a corresponding amendment to its implementation plan to the Minister under subsection 25.31 (3).

Implementation plans

By the IESO

25.31 (1) On the issuance of a directive under subsection 25.30 (1), the IESO shall, within the time specified in the directive, submit to the Minister an implementation plan containing an outline of the steps the IESO intends to take to meet the requirements set out in the directive including, if the directive requires it, the development of processes for entering into procurement contracts, processes for selecting transmitters, or both.

By the Board

News Release

Ontario Cutting Electricity Bills by 25 Per Cent

System Restructuring Delivers Lasting Relief to Households Across Province

March 2, 2017 9:40 A.M. | Office of the Premier

Ontario is lowering electricity bills by 25 per cent on average for all residential customers as part of a significant system restructuring that will address long-standing policy challenges and ensure greater fairness.

Starting this summer, Ontario's Fair Hydro Plan would provide households with this 25 per cent break. Many small businesses and farms would also benefit from the initiative. People with low incomes and those living in eligible rural communities would receive even greater reductions to their electricity bills. As part of this plan, rate increases over the next four years would be held to the rate of inflation for everyone.

These measures include the eight per cent rebate introduced in January and build on previously announced initiatives to deliver broad-based rate relief on all electricity bills.

Taken together, these changes will deliver the single-largest reduction to electricity rates in Ontario's history.

Recently, electricity rates have risen for two key reasons:

- Decades of under-investment in the electricity system by governments of all stripes resulted in the need to invest more than $50 billion in generation, transmission and distribution assets to ensure the system is clean and reliable
- The decision to eliminate Ontario's use of coal and produce clean, renewable power, as well as policies put in place to provide targeted support to rural and low-income customers, have created additional costs.

The burden of financing these system improvements and funding key programs has unfairly fallen almost entirely on the shoulders of today's ratepayers. To relieve that burden and share costs more fairly, two system fixes are being undertaken.

Recognizing that the electricity infrastructure that has been built will last for many decades to come, the province would refinance those capital investments to ensure that system costs are more equitably distributed over time. In addition, a number of important programs, such as the Ontario Electricity Support Program (OESP), will now be funded by the government instead of by ratepayers.

The province will also launch a new Affordability Fund, enhance the existing OESP and Rural or Remote Rate Protection (RRRP) program and provide on-reserve First Nations households with a delivery credit. These new measures will cost the government up to $2.5 billion over the next three years.

Notwithstanding that hydro rate relief costs will add significant pressure on the fiscal framework, the province continues to project a balanced budget for 2017-18, and will provide a full update on its fiscal plan in the spring budget.

Reducing electricity costs is part of Ontario's plan to create jobs, grow our economy and help people in their everyday lives.

Press Releases

DBRS

Insight beyond the rating.

Date of Release: March 3, 2017

DBRS Comments on Ontario's Plan to Reduce Electricity Prices

DBRS Limited (DBRS) has today commented on the Province of Ontario's (Ontario or the Province; rated AA (low) with a Stable trend by DBRS) plan to reduce residential electricity prices by 25%, as announced on March 2, 2017. DBRS views the proposed changes as credit neutral. The Province has the ability to absorb the fiscal impact of the proposed policy changes, while still restoring budgetary balance in 2017–2018. The Province has also indicated that it will seek to recover the debt and financing costs associated with reducing the Global Adjustment (GA) through future electricity rates.

The Province's plan to reduce residential electricity costs by 25% principally relies on (1) the provision of a rebate of the provincial portion of the harmonized sales tax (HST) for electricity (implemented in January 2017), (2) the enhancement of some targeted electricity cost-support programs and shifting the funding burden of those programs from electricity rates to taxpayers and (3) financing a portion of the GA.

The rebate for an amount equal to the provincial portion of the HST and funding of electricity cost-support programs using general revenue (as opposed to using electricity rates) have direct budgetary impacts for the Province. The Province has the fiscal capacity to absorb the impact of these changes — which will rise to approximately $2.0 billion annually over the next few years — without shifting the timeline to restore balance in 2017–2018. Ontario has indicated that it intends to maintain balanced results thereafter. DBRS will conduct a full review of the Province following the spring budget.

There are few details available about the plan to finance a portion of the GA at this time. The GA is, in substance, the difference between the market rate for electricity and that which is owed to generators based on regulated or contracted rates. The Province will honour existing agreements, leaving generators unaffected, and use debt to spread a portion of the electricity system costs over a longer period time. The Province expects the additional debt and financing costs to be recovered through future electricity rates.

The mechanics of the financing program have yet to be fully developed, although the Province does intend to introduce legislation during the spring sitting with implementation later this summer. DBRS understands that the plan requires $2.5 billion in annual borrowings, on average, over they first ten years to reduce the GA to a level consistent with the policy objective, although the exact amount to be borrowed in any given year and the number of years for which borrowing will be required will depend on prevailing electricity market conditions.

Ontario Power Generation Inc. (rated A (low) with a Stable trend by DBRS) will play a role in managing the financing program, but the exact legal structure for the financing program has yet to be determined. It is not clear who will issue debt, where it will reside or to what extent it may benefit from explicit Provincial support. Provided the debt continues to be fully supported by the electricity rate base, DBRS will treat it as self-supported and exclude it from the calculation of tax-supported debt. DBRS will re-evaluate once more information becomes available.

Notes:
All figures are in Canadian dollars unless otherwise noted.

The principal methodology is Rating Canadian Provincial Governments, which can be found on dbrs.com under Methodologies.

For more information on this credit or on this industry, visit www.dbrs.com or contact us at info@dbrs.com.

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Ontario hydro bill reductions to ultimately cost ratepayers more

ALLISON JONES, THE CANADIAN PRESS 03.02.2017 |

Ontario Premier Kathleen Wynne, right, speaks as Ontario Energy Minister Glenn Thibeault looks on during a press conference in Toronto on Thursday, March 2, 2017. The Liberal government unveiled its plan today to cut hydro bills, which are the biggest political issue it faces less than a year-and-a-half away from an election. THE CANADIAN PRESS/Frank Gunn

TORONTO - Soaring electricity bills in Ontario will see an average 17-per-cent cut this summer, a year before the provincial Liberals bid for re-election, but those savings will ultimately cost ratepayers billions in extra interest payments.

Premier Kathleen Wynne announced the savings Thursday, as well as further measures for rural and low-income customers, but acknowledged that the bill for the across-the-board relief will eventually come due for ratepayers.

"Over time it will cost a bit more. That's true," she said when detailing the plan. "And it will take longer to pay off. That's also true. But it is fairer because it doesn't ask this generation of hydro customers alone to pay the freight for everyone before and after."

Electricity bills in the province have roughly doubled in the last decade, rising faster than inflation since 2010, and have sparked increasing anger among Ontarians, leading to plummeting approval ratings for Wynne.

Progressive Conservative Leader Patrick Brown said those low poll numbers are what was behind the government's move.

"I think right now they're looking at their own political survival," he said. "They're trying any Hail Mary and they're trying to put a bandage on a bullet wound."

The Liberals shot back at Brown, saying that his party has no plan of its own to deal with electricity bills, but he said it will be unveiled "soon."

Ontario NDP deputy leader Jagmeet Singh said the new plan is long-term pain for short-term gain.

"The Liberals' plan is essentially to kick this can down the road — not deal with it now, not fix the root cause, but literally take the can and kick it way down the road so they can get re-elected," he said.

Wynne said the increasing hydro bills in the province were due to investments in the grid, nuclear refurbishments and getting rid of coal. She also acknowledged that long-term contracts for green energy producers at above-market rates were "too generous."

Ontario now has a clean and reliable system, Wynne said, but the entire burden of those investments was being shouldered by current ratepayers when the benefits will be seen over many years.

Most of the electricity generation contracts in Ontario are for 20 years, so refinancing them is like re-amortizing a mortgage over 30 years instead. But that will come with up to $1.4 billion a year in extra interest payments.

The annual $1.4 billion is a maximum figure and Energy Minister Glenn Thibeault said the government expects its plan to cost about $25 billion over 30 years. But the opposition parties said the costs could be more like $42 billion.

In the near term, hydro rates will also be held to the rate of inflation, and the plan is for the 17-per-cent cut to be reflected in the Ontario Energy Board's May 1 rates so customers see it reflected on their June bills.

But those extra interest costs will be added back onto bills in the future.

Legislation will be introduced to allow the Independent Electricity System Operator and Ontario Power Generation to refinance a portion of the global adjustment charge.

That's the charge consumers pay for above-market rates for power producers. The auditor general has estimated the global adjustment charge cost $50 billion between 2006 and 2015 and increased by 1,200 per cent between 2006 and 2013 — meanwhile, the average electricity market price dropped by 46 per cent.

The across-the-board relief of 17 per cent comes in addition to an eight-per-cent rebate that took effect Jan. 1. That cut is estimated to cost taxpayers about $1 billion per year.

Several other measures were announced Thursday to help low-income and rural residents at a cost of $2.5 billion over three years to taxpayers.

Customers under a program that gives a rate subsidy to those in rural and remote areas will be expanded so that ratepayers covered by local distribution companies with the highest delivery charges will see those rates cut between $12 and $75.

The Ontario Electricity Support Program for low-income ratepayers will be funded through government revenues instead of other taxpayers. The benefits are also being increased, so that someone who qualifies for the smallest credit — a single person earning less than $28,000 — would save $45 a month instead of $30.

Customers who qualify for both the OESP and the expanded rural subsidy would see their bills reduced by up to 50 per cent, the government said.

under pressure during the execution of the DRP as a result of reduced nuclear generation, elevated capital expenditures for the refurbishment, deferral of collection of a portion of the approved revenue requirements under nuclear rate smoothing, and resulting higher debt levels and the potential need for additional external financing. For example, in its July 2015 report downgrading OPG from A- to BBB+, S&P stated:

> *We expect the Company to continue with a number of projects that require significant capital spending, about C$1.6 billion per year, over the next two years including the Darlington nuclear facility refurbishment plus the additional maintenance capital expenditures, which pressures the credit metrics. We forecast adjusted funds from operations (AFFO)-to-debt of 14%-16% for each of 2015 and 2016 before dropping to about 13% in 2017, when the Darlington refurbishment project execution starts.*[50]

With respect to nuclear rate smoothing, the incremental increase in financial risk arises, in part, due to inherent uncertainty related to the collection of amounts deferred for a decade into the future. The other major risk with nuclear rate smoothing is the uncertainty associated with the smoothed payment amount level established during the DRP (both in the upcoming and future proceedings), which Concentric understands is at the OEB's discretion under O.Reg. 53/05. As such, the Company is exposed to a risk of lower than expected cash flow levels that could impact the Company's credit metrics, as well as its ability to meet long-term obligations, undertake capital expenditures and otherwise manage cash needs. Concentric notes that, according to OPG's 2016-2018 Business Plan, which also includes financial projections for the 2019-2021 period, the Company's credit metrics are under some pressure during the period to 2021 even assuming an 11% per year nuclear rate smoothing increase. According to the business plan, one of the two key credit metrics monitored by S&P (*i.e.*, the debt-to-EBITDA ratio) is projected to breach threshold levels in at least two years of the upcoming five-year rate period.

Another area of incremental financial risk for OPG relates to the recovery of its pension and OPEB costs, even assuming the continuation of the Company's Pension and OPEB Cost Variance account.[51] Specifically, in EB-2013-0321, the Board authorized OPG to recover its cash requirements for pensions and OPEBs, approving a pension and OPEB revenue requirement of $836.9 million compared to OPG's $1.3 billion proposed accrual-basis pension and OPEB costs. In doing so, the OEB also approved a deferral account to track the difference between cash and accrual based costs for pensions and OPEBs, but left the eventual disposition of the account uncertain.[52] The OEB noted the disposition of that account would be informed by the outcome of a future generic proceeding.[53] In EB-2031-0321, the OEB also left open the issue of whether to transition away from the accrual basis of recovery in the future, based on the outcome of the generic proceeding. On May 14, 2015,

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50 Standard & Poor's Ratings Services, "Ontario Power Generation Inc. Rating Lowered to 'BBB+' from 'A-' on Province of Ontario Downgrade; Outlook Stable," July 7, 2015, at 3.

51 In EB-2013-0321, the OEB found that OPG's Pension and OPEB Cost Variance Account reduced the Company's forecast risk associated with pension and OPEB costs. As such, the risk mitigating properties of that account are already factored into OPG's current equity ratio (*i.e.*, 45%). Therefore, from the perspective of changes in OPG's risks since EB-2013-0321, continuation of that account or an equivalent account if the OEB includes Pension/OPEB costs in OPG's revenue requirement on a basis other than accrual in the upcoming proceeding would be risk neutral.

52 EB-2013-0321, Decision with Reasons, at 88-89.

53 The deferral account has enabled OPG to continue to record income for the period on an accrual rate recovery basis for pension and OPEB.

CCC Interrogatory #11

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/p. 4
The evidence states:
"While OPG believes that the forecast credit metrics and operating cash flows in the 2016-2018 Business Plan will support investment grade credit rating, a different outcome of this application, including with respect to the nuclear rate smoothing trajectory, could result in a weaker financial position and increase the risk of a credit rating downgrade during a period of increased borrowing."

a. Please explain, specifically, how a different outcome regarding rate nuclear rate smoothing could result in a weaker financial position for OPG.

Response

The statement cited in the question refers to the fact that an approved smoothed nuclear rate that is lower than proposed by OPG in this application (and reflected in OPG's 2016-2018 Business Plan) would reduce OPG's cash flow, increase debt, weaken key financial metrics, and increase the risk of a negative effect on the company's credit rating relative to business plan forecasts.

Board Staff Interrogatory #21

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

Interrogatory

Reference:
Ref: Exh C1-1-1 Attachment 1, pages 18-26

Pages 18-23 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments in which it concludes that OPG's operational, regulatory and political risk with respect to the nuclear generation assets increases, while acknowledging that there are some mitigating factors with respect to OPG's approach to project planning and management of the DRP and the provisions of O.Reg. 53/05 effective January 1, 2016.

Pages 24-26 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments of OPG's rate proposals. In particular, on the middle of page 26, Concentric describes the nuclear rate smoothing proposal and how the variance between revenues and revenue requirement will be tracked in the rate smoothing deferral account per O.Reg. 53/05.

Nonetheless, Concentric concludes on page 26:

> Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

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[2]Further, for hydroelectric, any difference in the revenue requirement between the current 45% equity thickness and that determined by the OEB in its decision to this application, and which OPG has proposed to be 49%, would be tracked for later disposition.
[3] Currently *Report of the Board on the Cost of Capital for Ontario's Rate-regulated Utilities, (EB-2009-0084)*, December 11, 2009.

The discussions on pages 18-23 and on page 26 are fully qualitative in nature. With respect to the nuclear rate setting proposal, please indicate how Concentric has translated the qualitative points on these pages to conclude that, as a result, OPG is exposed to "material incremental risk" over the 2017-2021 plan period.

in Exhibit A1-3-3 Page 2, under OPG's rate smoothing proposal the Company will defer $1.6 billion, or nearly 10% of the nuclear revenue requirement, through 2021. That will decrease cash flow relative to what it would be absent smoothing. This deferral of revenue and reduced cash flow will occur during a period in which OPG forecasts issuing $4 billion in debt, and the maintenance of credit support is critical (*see*, Exhibit A1-3-3 page 4). Incremental increase in financial risk arises, in part, due to inherent uncertainty related to the collection of amounts deferred for a decade into the future (*see*, Exhibit C-1-1/Attachment 1, at 28).

From a business risk perspective, the risks discussed in the Concentric report and summarized above could manifest themselves in terms of variability in cash flows and earnings that impact the ability of OPG to recover its costs. That variability in cash flows and earnings could occur through either changes in cost levels or changes in generation levels (or both). In Concentric's opinion, the combination of the factors described in the Concentric report and summarized above could lead to significant variability in cash flows and earnings, and thus, in conjunction with the increasing proportion of nuclear power in OPG's generation mix, combine to create material incremental risk for the Company.

From an investor's perspective, the business risk assessment process is inherently qualitative in nature and involves the application of reasoned judgment on the part of the analyst. In fact, the business risk analyses performed by credit ratings agencies such as S&P, Moody's, and DBRS are largely qualitative in nature as well. For instance, the ratings agencies stress the importance of factors such as the quality, consistency and predictability of the regulatory regime in which a utility operates, and the types of businesses in which a utility engages (*e.g.*, transmission and distribution vs. generation). In addition, Concentric's comparative risk analysis, presented in Exhibit C1-1-1 Attachment 1, pages 30 through 41, is used in conjunction with Concentric's business risk assessment of OPG to provide context for where, within a reasonable range, OPG's equity ratio should be set by the Board. Based on the combination of those analyses, Concentric concluded that an equity ratio of no less than 49% was appropriate for OPG.

Chart 3: Proposed and Alternative Rate Smoothing Scenarios

	Original 11% Proposal[1]	A	B (Proposed)	C	D	E
2017-2021 Average Annual Change in WAPA	**4.3%**	2.0%	**2.5%**	3.0%	3.5%	4.0%
2022-2026 Average Annual Change in WAPA[2]	**6.9%**	8.3%	**7.0%**	5.7%	4.3%	3.0%
2027-2036 Average Annual Change in WAPA[2]	**(1.9)%**	(1.5)%	**(1.0)%**	(0.3)%	0.5%	1.2%
Peak RSDA Balance ($B)	**$3.3**	$3.2	**$2.9**	$3.0	$3.2	$3.4
Total Interest ($B)	**$1.4**	$1.4	**$1.4**	$1.4	$1.4	$1.4
Interest Cost / Deferred Revenue Ratio	**0.5**	0.5	**0.5**	0.5	0.5	0.4
FFO Interest Coverage > = 3 (2017-2021) / (2022-2026)	**3.6 / 5.3**	4.5 / 5.0	**4.6 / 5.4**	4.6 / 5.8	4.7 / 6.2	4.8 / 6.7
DEBT to EBITDA < = 5.5 (2017-2021) / (2022-2026)	**6.2 / 5.3**	5.9 / 5.3	**5.9 / 5.2**	5.8 / 5.0	5.8 / 4.9	5.7 / 4.7
Nuclear Payment Amount Transition Impact ($/MWh)	**($4.3)**	$1.0	**($3.7)**	($9.3)	($16.8)	($22.7)
Average Annual Bill Impact (2017-2021) in %	**0.7%**	0.3%	**0.4%**	0.5%	0.6%	0.7%
Average Annual Bill Impact (2017-2021) in $	**$1.05**	$0.51	**$0.65**	$0.79	$0.93	$1.07
Average Annual Bill Impact (2017-2036) in %[2]	**0.3%**	0.3%	**0.3%**	0.4%	0.4%	0.4%
Average Annual Bill Impact (2017-2036) in $[2]	**$0.43**	$0.43	**$0.47**	$0.53	$0.60	$0.65

Notes

[1] Updated to reflect changes to Nuclear revenue requirement in Ex. N1-1-1 and Ex. N2-1-1. Nuclear Payment Amount smoothing is inherently more volatile than smoothing based on WAPA. This is primarily due to the impact that year-over-year production differences have on the annual WAPA, as well as the expiry of higher payment riders in effect during 2016. The average year-over-year change in the WAPA shown for the Original 11% Proposal is therefore not directly comparable with the more consistent year-over-year change in the period in the smoothing scenarios under the amended Regulation.

[2] Calculated assuming that hydroelectric payment amounts continue to escalate at 1.5% per year throughout the 2017-2036 period pursuant to the price-cap as proposed in Ex. I1-2-1 Table 1 and no payment riders beyond those proposed in this application.

Based on its assessment of the alternatives above, using the considerations described in section 4.0 above, OPG proposes an average annual WAPA increase of 2.5% per year during the 2017-2021 period. This rate of increase would result in an average year-over-year increase of approximately $0.65 on the typical residential customer's monthly bill during the 2017-2021 period. The methodology by which OPG calculated customer bill impacts in Chart 3 is provided in Section 5.2 above.

i. Financial Viability (Leverage and Cash Flow Impacts): Higher values for the FFO Adjusted Interest Coverage ratio and lower values for the Debt to EBITDA credit metric reduce financial risk to OPG. OPG applied "financial viability" as a threshold criterion to identify the range of potentially acceptable rate smoothing alternatives shown in Chart 3. OPG assessment was based on at least one of the two metrics cited above being within threshold at all times during each of the two 5-year deferral periods (i.e., 2017 to 2021 and 2022 to 2026).

ii. Long-Term Perspective: The assessment was based on the size of the average change in rates during the recovery period (closer to 0 per cent is better).

iii. Post-Recovery Transition: The assessment was based on the size of the change in rates at the end of the recovery period (smaller is better) to the forecast steady state rate of approximately $120/MWh.

iv. Intergenerational Equity: The assessment was based on the ratio of total interest costs to total amounts deferred (total interest / total amounts deferred). The lower the ratio, the lower the cost of deferring revenue under that alternative. Intergenerational equity involves striking a balance between the benefits of deferring revenue and the costs of the deferral; therefore OPG's assessment placed value on a ratio that best reflects this balance (i.e., neither the highest nor the lowest ratio).

v. Customer Bill Impact: The assessment was based on average customer monthly bill impacts for the entire deferral and recovery period. Consistent with the Rate Stability criterion, the impact was determined using a constant rate increase during the deferral period (i.e., both 2017 to 2021 and 2022 to 2026) and a constant rate change during the recovery period (2027 to 2036) as identified in Chart 3. Lower customer bill impacts are better.

In OPG's assessment, the 11 per cent smoothing is the best alternative as it was either the best or second best on four of the five considerations above, and no worse than third best on the remaining consideration. The proposed nuclear payment amounts proposed in Ex. I1-3-1 have been determined based on this level of deferred recovery. OPG therefore proposes to defer the collection of approximately $1.6B in nuclear revenue requirements for 2017 through

2021, which is the sum of the deferred revenue requirement amounts for those years shown in Chart 4.

Chart 4

OPG Proposed Deferred Nuclear Revenue Requirement[17]

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,489
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 683	$ 440	$ 121	$ 413	$ (46)

3.0 MID-TERM PRODUCTION REVIEW

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:

1) an update of the nuclear production forecast and consequential updates to nuclear fuel costs underpinning the payment amounts for the final two-and-a-half years of the five-year application period (July 1, 2019 to December 31, 2021); and
2) disposal of applicable audited deferral and variance account balances (most accounts would reflect amounts accumulated over the period January 1, 2016 to December 31, 2018) as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018.

3.1 Rationale for Mid-Term Review

In this application, OPG has provided a nuclear production forecast that covers the full five-year period from January 1, 2017 to December 31, 2021. The company's nuclear production forecast and forecasting process are described in detail in Ex. E2-1-1. The production forecast is based on a set of current assumptions that are challenging to meet, with the risk of

[17] Proposed Revenue Requirement per Ex I-1-1 Table 2
Forecast Production per Ex E-2-1 Table 1
Smoothed Rate determined by escalating the existing $59.29 approved nuclear payment amount from EB-2013-0321 by 11% each year
Smoothed Revenue determined by applying the Smoothed Rate to the Forecast Production
Deferred Revenue calculated as the difference between the Proposed Revenue Requirement and the Smoothed Revenue

OPG's proposal results in deferring the collection of approximately $1B in revenue in the 2017 to 2021 period, as reflected in Chart 4 below. This is approximately $0.4B less than OPG proposed to defer under the previous proposal (after adjustments to account for the reduced nuclear revenue requirement in the previous impact statements). The nuclear payment amounts have been updated based on the level of deferred recovery associated with this proposal.

Chart 4: OPG Proposed Deferred Revenue Requirement

	2017	2018	2019	2020	2021	Total
Proposed Revenue Requirement ($M)	$ 3,161	$ 3,186	$ 3,273	$ 3,783	$ 3,398	$ 3,617
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38	26.01
Smoothed Rate ($/MWh)	$ 76.39	$ 78.60	$ 84.83	$ 88.21	$ 92.02	N/A
Smoothed Revenue ($M)	$ 2,910	$ 3,024	$ 3,311	$ 3,295	$ 3,256	$ 15,796
Deferred Revenue Requirement ($M)	$ 251	$ 162	$ (38)	$ 488	$ 142	$ 1,005

7.0 IMPLEMENTATION

The specific revenue requirement deferral amounts proposed in section 6.0 are produced by adjusting the approved nuclear payment amounts to achieve the desired annual rate of change in the total WAPA. The OEB's findings on the proposed nuclear revenue requirements, nuclear production forecast, hydroelectric and nuclear payment riders and the hydroelectric IRM formula will necessarily impact the 2017-2021 NPA, the annual deferred nuclear revenue requirement, and the resulting WAPA.

Nuclear rate smoothing is unique in terms of the magnitude of the proposed deferred amounts, and the number of interrelated decisions required. To the extent the OEB's decision changes the rate smoothing inputs, it may be expedient for the OEB to make a decision on the nuclear revenue requirements and the inputs (steps 2 and 3 of the chart in section 3.1 above), and withhold its final decision on the "outputs" (i.e., the annual change in WAPA, the resulting nuclear payment amount, and the amount to be deferred in the RSDA) until the Payment Amount Order approval process (steps 4, 5 and 6).

AMPCO Interrogatory #16

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

Interrogatory

Reference:
Ref: C1-1-1- Page 1

a) Please provide the annual impact on revenue requirement if the current capital structure is maintained.

Response

The annual impact on the Nuclear revenue requirement if the current capital structure is maintained is provided in Attachment 1.

See Ex L-1-9.8 Staff-217 for the expected entry into the Hydroelectric Capital Structure Variance Account.

Numbers may not add due to rounding.

Table 1
Calculation of Cost of Capital Using Current and Proposed Capital Structure ($M)

Line No.	Description	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)
1	**Nuclear Rate Base**[1]	3,344.4	3,513.9	3,449.8	7,494.0	7,959.1
2	**ROE**[2]	9.19%	9.19%	9.19%	9.19%	9.19%
3	**Cost of Debt**[2]	4.91%	4.63%	4.56%	4.52%	4.51%
4	**Deemed Equity (Proposed)**[2]	49%	49%	49%	49%	49%
5	**Deemed Debt (Proposed)**[2]	51%	51%	51%	51%	51%
6	**Proposed WACC**[3]	7.0%	6.9%	6.8%	6.8%	6.8%
7	**Deemed Equity (EB-2013-0321)**	45%	45%	45%	45%	45%
8	**Deemed Debt (EB-2013-0321)**	55%	55%	55%	55%	55%
9	**Proposed WACC (At EB-2013-0321 Capital Structure)**[4]	6.8%	6.7%	6.6%	6.6%	6.6%
10	**Revenue Requirement (Proposed)**[5]	284.5	293.9	287.4	622.7	660.8
11	**Revenue Requirement (At EB-2013-0321 Capital Structure)**[6]	274.6	283.2	276.7	599.5	636.1
12	**Revenue Requirement Impact if EB-2013-0321 Capital Structure is Maintained**[7]	**(9.8)**	**(10.7)**	**(10.6)**	**(23.2)**	**(24.7)**

Notes
1 Ex. B1-1-1 Table 2, line 7 minus the Adjustment for Lesser of UNL or ARC from Ex. C1-1-1 Tables 1-5, line 7
2 C1-1-1Tables 1-5
3 Calculated as: (Line 2 X Line 4) + (Line 3 X Line 5)
4 Calculated as: (Line 2 X Line 7) + (Line 3 X Line 8)
5 (Line 1 x Line 6) + (Line 1 x Line 2 x Line 4) x (tax rate / 1- tax rate), where the tax rate is 25%
6 (Line 1 x Line 9) + (Line 1 x Line 2 x Line 7) x (tax rate / 1- tax rate), where the tax rate is 25%
7 (Line 11 - Line 10)

VECC Interrogatory #6

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

Interrogatory

Reference:
Reference: C1/T1/S1

In terms of the return on equity (ROE):

a) Please provide the actual return on equity for each year since and including 2005.

b) Please provide the approved ROE for each year since 2005.

c) Please indicate how the approved ROE was set for each year.

d) Please explain the factors that generated any differences between the actual and approved ROE.

e) Please indicate which periods OPG was regulated under any measures that could be defined as performance based incentive regulation.

f) With reference to the request deferral account on page 2, please provide a list of all the variance accounts available to OPG's regulated operations and the year end 2016 balances in each.

Response

a) OPG's actual return on equity for 2005-2015 is provided in Chart 1 below

Chart 1

2005	2006	2007	2008	2009	2010
2.43%	5.70%	(6.70)%	(3.11)%	1.10%	4.71%
2011	**2012**	**2013**	**2014**	**2015**	
4.80%	4.73%	0.46%	6.32%	3.63%	

b) OPG's OEB approved ROE is provided in Chart 2 below. OPG's first rates application to the OEB was EB-2007-0905 where the OEB approved an ROE for 2008 and 2009. As such OPG does not have an OEB approved ROE prior to 2008.

Chart 2

2008	2009	2011	2012	2014	2015
EB-2007-0905	EB-2007-0905	EB-2010-0008	EB-2010-0008	EB-2013-0321	EB-2013-0321
8.65%	8.65%	9.43%	9.55%	9.36%	9.30%

c) OPG's OEB approved ROE have been set as follows:
EB-2007-0905: Set at 8.65% consisting of a forecast long-term risk free rate of 4.75%, a risk premium of 3.4%, and a 0.5% adjustment for financing flexibility[1].
EB-2010-0008: Set at 9.43% for 2011 based on Bloomberg LLP, Consensus Forecasts, and Bank of Canada data for November 2010, which is three months in advance of March 1, 2011, and using the ROE methodology in Appendix B of the Cost of Capital Report[2]. Set at 9.55% for 2012 based on the Global Insight forecast and the OEB's methodology[3].
EB-2013-0321: Set at the OEB's Return on Equity for 2014 at 9.36%. Set at 9.3% for 2015 using the OEB's 2015 cost of capital parameters[4].

d) OPG's actual ROE has varied from OEB approved values predominantly as a result of variances in actual expenditures and nuclear production from OEB approved forecasts.

e) OPG has not previously been regulated under measures defined as performance based incentive regulation.

f) Attachment 1 provides the list of all variance and deferral accounts currently authorized for OPG's regulated operations and the projected year-end 2016 balances and activity therein, in the form of Ex. H1-1-1 Table 1a. The projected balances are based on 2016 forecasts in the pre-filed evidence, as updated for the impact on the pension contributions of the January 1, 2016 actuarial valuation of the OPG pension plan (see Ex. L-6.6-1 Staff-156).

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[1] See EB-2007-0905 Decision with Reasons, Pages 157-158
[2] See EB-2010-0008 Decision and Order, Page 122
[3] See EB-2010-0008 Decision and Order, Page 123
[4] See EB-2013-0321 Decision and Order, page 117

CCC Interrogatory #15

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

Interrogatory

Reference: H1/T1/S1

Please set out how much of OPG's revenue requirement for both the hydroelectric business and nuclear business are subject to deferral account treatment

Response

Assuming that the existing deferral and variance accounts are authorized to continue, OPG estimates that in the order of 20%-30% of the 2017-2021 revenue requirement would be at least partially subject to deferral and variance account treatment. In making this estimate, OPG used the 2017-2021 nuclear revenue requirement proposed in this application and the average of 2014/2015 hydroelectric revenue requirements approved in EB-2013-0321, adjusted to remove the one-time allocation of nuclear tax losses to the hydroelectric business consistent with OPG's "going in" rates under its IRM proposal (Ex. A1-3-2, section 2.3.2).

In order to arrive at the 20%-30% estimate, OPG has taken the sum of all elements of the revenue requirement that are subject to deferral and variance account treatment and divided those amounts by the total revenue requirement. This indicates how much of the revenue requirement is subject to deferral and variance accounts, but does not provide an estimate of the amounts that will be recorded as entries into these accounts. For example, the calculation of the 20-30% range includes the full forecast cash pension and OPEB cash amounts embedded in the revenue requirement; however; only variances from these amounts would be recorded into the associated Pension & OPEB Cash Payment Variance Account. In addition, the disposition of balances [not all balances are subject to prudence, such as NLDA] in the deferral and variance accounts is subject to a prudence review.

As discussed in Undertaking J3.9 in EB-2013-0321, some elements of the revenue requirement are subject to accounts that do not cover all sources of variance from forecast amounts. For example, the Income and Other Taxes Variance Account captures only certain variances, such those related to changes in tax rates or rules and income tax audits, but not other sources of variance. Nevertheless, these elements of the revenue requirement are included in the 20%-30% figure above even though they are only subject to deferral or variance account treatment in certain circumstances.

As noted in EB-2007-0905, one of OPG's deferral and variance accounts is unrelated to the prescribed facilities, the Bruce Lease Net Revenues Variance Account, but it is included in the estimate provided above (EB-2007-0905, Decision with Reasons, November 3, 2008, page 147).

Based on its nuclear rate smoothing proposal, OPG also is proposing to defer the collection of an average of 10% of the annual nuclear revenue requirement, but this amount is not considered in the estimate provided above. For clarity, amounts to be recorded in the associated Rate Smoothing Deferral Account would be fixed in this proceeding based on the approved revenue requirement (see Ex. H1-1-1 section 6.1). Variances from the approved revenue requirement subject to deferral and variance account treatment (i.e., those in the 20-30% range) would be recorded in the applicable deferral and variance accounts in the same manner as previously, notwithstanding the amount deferred under rate smoothing.

BCG

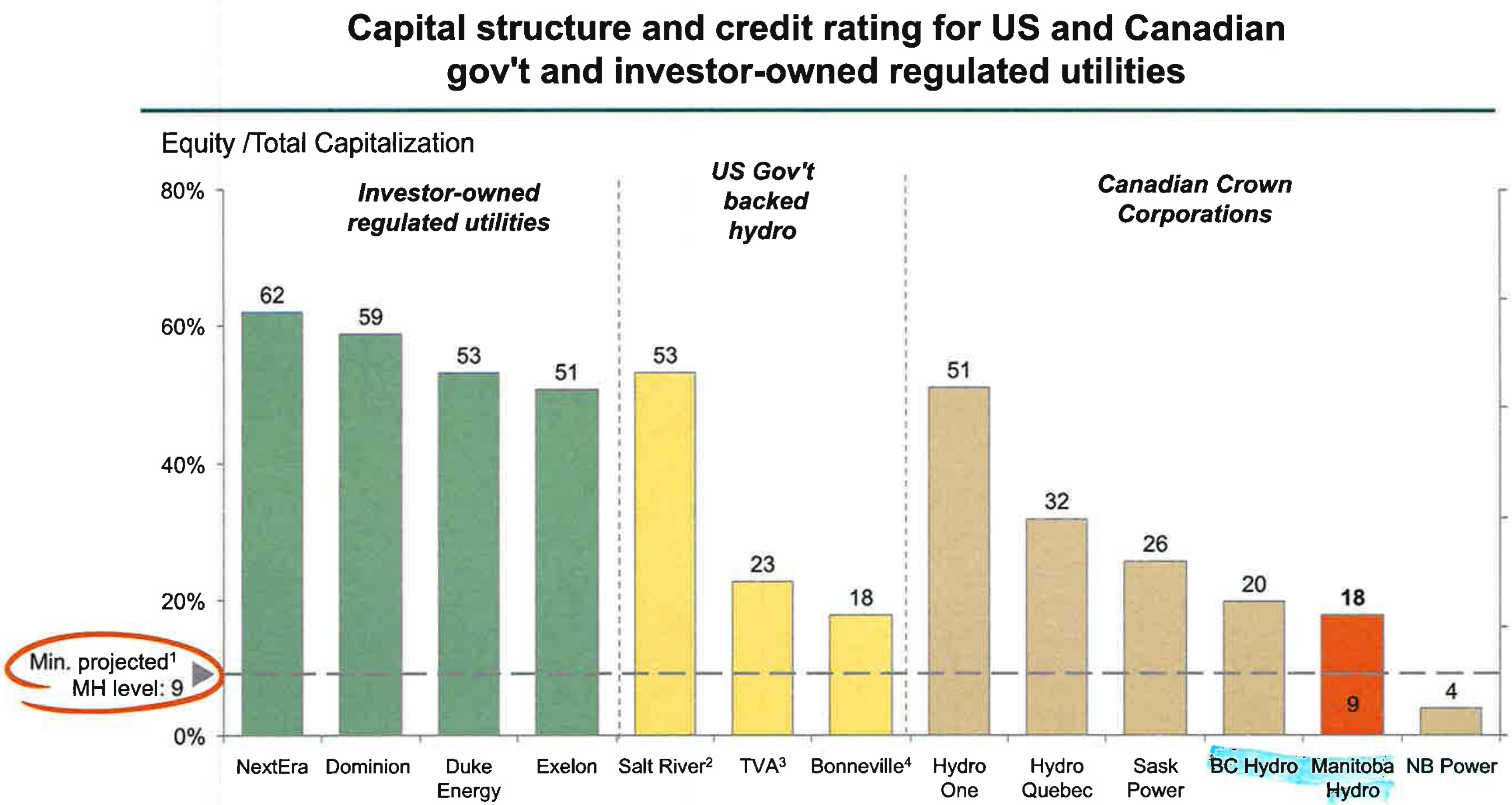
Manitoba Hydro

Bipole III, Keeyask and Tie-Line review

September 19, 2016

THE BOSTON CONSULTING GROUP

Exhibit 18: Equity ratios well-below most peers



1. 2022 Expected Equity Ratio on NFAT Base Case 2. Salt River Project an entity of the State of Arizona 3. Federally owned corporation 4. US Federal administration within Dept. of Energy
Source: 2015 Audited Financial statements, SNL

British Columbia Hydro and Power Authority

2015/16
ANNUAL SERVICE PLAN REPORT

BRITISH
COLUMBIA

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)		**2016**		2015		Change
Total Revenues	**$**	**5,657**	$	5,748	$	(91)
Net Income	**$**	**655**	$	581	$	74
Capital Expenditures	**$**	**2,306**	$	2,169	$	137
GWh Sold (Domestic)		**57,300**		51,213		6,087

as at March 31 ($ in millions)		**2016**		2015		Change
Total Assets	**$**	**30,034**	$	27,753	$	2,281
Shareholder's Equity	**$**	**4,500**	$	4,170	$	330
Accrued Payment to the Province	**$**	**326**	$	264	$	62
Retained Earnings	**$**	**4,397**	$	4,068	$	329
Debt to Equity		**80 : 20**		80 : 20		n/a
Number of Domestic Customer Accounts		**1,960,555**		1,935,068		25,487
Total Reservoir Storage (GWh)		**16,518**		19,565		(3,047)

REVENUES

Total revenues after regulatory account transfers for the year ended March 31, 2016 were $5,657 million, a decrease of $91 million or 2 per cent compared to the prior fiscal year. The decrease was primarily due to lower trade revenues mainly due to a decrease in the average natural gas price and decreases in volumes of physical gas and electricity sold, partially offset by higher domestic revenues primarily due to higher average customer rates and higher surplus energy sales.

	(in millions)				*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31		**2016**		2015	**2016**	2015	**2016**	2015
Domestic								
Residential	**$**	**1,842**	$	1,712	**17,331**	17,047	**$ 106.28**	$ 100.43
Light industrial and commercial		**1,685**		1,597	**18,421**	18,564	**91.47**	86.03
Large industrial		**766**		748	**13,669**	14,020	**56.04**	53.35
Other energy sales		**464**		280	**7,879**	1,582	**58.89**	176.99
Total Domestic Revenue Before Regulatory Transfer		**4,757**		4,337	**57,300**	51,213	**83.02**	84.69
Rate smoothing and load variance regulatory transfer		**299**		492	**-**	-	**-**	-
Total Domestic	**$**	**5,056**	$	4,829	**57,300**	51,213	**$ 88.24**	$ 94.29
Trade								
Electricity - Gross	**$**	**643**	$	989	**14,732**	21,928	**$ 43.65**	$ 45.10
Less: forward electricity purchases		**(183)**		(214)	**-**	-	**-**	-
Electricity - Net		**460**		775	**-**	-	**-**	-
Gas - Gross		**462**		886	**17,042**	21,637	**27.11**	40.95
Less: forward gas purchases		**(321)**		(742)	**-**	-	**-**	-
Gas - Net		**141**		144	**-**	-	**-**	-
Total Trade [1]	**$**	**601**	$	919	**31,774**	43,565	**$ 18.91**	$ 21.09
Total	**$**	**5,657**	$	5,748	**89,074**	94,778	**$ 63.51**	$ 60.65

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.*

[2] *The Trade $/MWh figures are based on total gross sales which includes physical and financial transactions whereas the volumes only include physical transactions.*