

**CCC Interrogatory #020**

**Interrogatory**

**Reference:  
Exhibit C1, Tab 1, Schedule 1**

Question(s):

- a) Please advise whether the Government of Ontario is explicitly aware of OPG's proposal to increase the equity thickness from 45% to 52% for the test period. If so, please explain how the government was informed of this proposal. As part of the response, please also discuss whether the Government of Ontario is aware of the bill impacts resulting directly from this change.
- b) Please provide the impact on total 2027-2031 revenue requirement of a 1% change to equity thickness based on the proposals in the application.
- c) Please file on the record of the current proceeding all of the cost of capital-related studies that were filed in the EB-2016-0152 and EB-2020-0290 proceedings.

**Response**

- a) OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on communications with the Province of Ontario that is not relevant to deciding any issue on the approved Issues List in this application.
- b) A 1% reduction in proposed equity thickness for OPG's prescribed facilities (i.e., to 51% equity) would result in an aggregate reduction of approximately \$38M for the proposed nuclear revenue requirements over 2027-2031, and a reduction of \$7M for the proposed 2027 hydroelectric revenue requirement.
- c) Attachment 1 and Attachment 2 provide OPG's common equity reports filed in EB-2016-0152 and EB-2020-0290, respectively.

COMMON EQUITY RATIO:  
**FOR OPG'S REGULATED GENERATION**

PREPARED FOR  
ONTARIO POWER GENERATION  
MAY 2016



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SECTION 1:

## EXECUTIVE SUMMARY

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Concentric Energy Advisors, Inc. (“Concentric”) was retained to prepare this independent report as to whether the application of the cost of capital approved by the Ontario Energy Board (“OEB” or the “Board”) in EB-2013-0321 is an appropriate basis for setting Ontario Power Generation’s (“OPG’s” or the “Company’s”) nuclear and hydroelectric payment amounts in OPG’s next rate application.<sup>1</sup> Concentric’s analysis specifically focused on OPG’s capital structure.

The Board previously found that the approach to establishing OPG’s capital structure should be based on a detailed risk analysis of OPG, along with the changes to the Company’s risk profile. That approach should also include an assessment of OPG’s relative risk compared to other utilities. The Board has also applied the fair return standard in establishing the cost of capital for the utilities it regulates, which requires that three standards for the cost of capital be met: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard.

Concentric’s analysis focused on: (a) changes to OPG’s business and financial risks since EB-2013-0321; (b) expected changes to OPG’s risk profile and financial integrity on a forward-looking basis, consistent with how an investor would analyze the Company; and (c) for comparative purposes, a review of capital structure data for similar North American electric utilities.

Specific to changes to OPG’s business and financial risks since EB-2013-0321, Concentric reviewed both OPG’s regulated hydroelectric and nuclear businesses, as well as the Company’s anticipated rate proposals in the upcoming rate proceeding, and its overall regulatory environment.

As of December 31, 2015, OPG’s regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington), as well as 54 of the hydroelectric generating stations (“prescribed” facilities). OPG recently announced that it is to begin a \$12.8 billion project to refurbish the Darlington facility starting in October 2016. That “megaproject” will more than double OPG’s nuclear rate base.<sup>2</sup>

In terms of the hydroelectric business, the major risks generally faced by a regulated utility 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.

Concentric concludes that, based on the above, OPG’s business risks related to its prescribed hydroelectric facilities have remained relatively the same since EB-2013-0321, with the exception of regulatory risk. The Company’s regulatory risk is expected to increase during the period for which rates are expected to be set in the upcoming proceeding as a result of the movement to a five-year rate plan, as described further herein. Specifically, in Concentric’s view, there is an anticipated

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<sup>1</sup> References to OPG or the Company throughout the report should be read as references to OPG’s regulated operations.

<sup>2</sup> Megaprojects are large, complex industrial construction projects. The construction industry handbook “Industrial Megaprojects: Concepts, Strategies, and Practices for Success” defines megaprojects as any project with a total capital cost of more than \$1 billion (in 2003 U.S. dollars). *See*, Merrow, Edward W., “Industrial Megaprojects: Concepts, Strategies, and Practices for Success,” John Wiley & Sons, Inc., 2011, at 15.

change in risk related to OPG's hydroelectric facilities that is attributable to the transition from a two-year cost of service rate-setting term to a five-year incentive regulation ("IR") regime.

In terms of the nuclear business, the major risks generally faced by a regulated utility include: (1) the ability to implement large and complex nuclear projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Specific to OPG, the \$12.8 billion Darlington Refurbishment Project ("DRP") presents an incremental source of risk to the Company that will increase during the period for which rates in the upcoming proceeding are expected to be set. OPG's plans to pursue extended Pickering operations beyond 2020, the longest any Canadian Deuterium Uranium ("CANDU") plant will have ever operated, also poses risks. In addition, OPG continues to face risks related to the implementation of new safety and regulatory requirements. OPG's forecasts for costs and generation at its Darlington and Pickering nuclear facilities are being made in the face of these uncertainties, which are magnified by the longer, five-year term under the Company's ratemaking proposals, subject to the proposed mid-term review, discussed herein.

With the investment in OPG's regulated nuclear business due to the DRP, the nuclear operations are also projected to comprise a comparatively larger portion of OPG's overall regulated rate base than it did as of EB-2013-0321. The Board has recognized that nuclear assets are higher in risk than hydroelectric assets. The relative increase in nuclear assets as a percentage of rate base during the five-year rate period and beyond indicates that, all else being equal, OPG will become more risky over time.

Concentric concludes that OPG's risk profile will change materially over the 2017-2021 period as compared to its risk profile at the time of EB-2013-0321. Specifically, OPG's generation mix will change to reflect a significantly higher proportion of nuclear rate base than when the Board set the common equity ratio at 45% in EB-2013-0321. In fact, by the end of the test period in 2021, the nuclear rate base will exceed the relative level at which it stood when the Board set OPG's common equity ratio at 47% in EB-2007-0905 and EB-2010-0008. Given the Board's EB-2013-0321 finding that "[t]he business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets,"<sup>3</sup> the opposite must hold equally true: business risk will have increased because of the addition of significant nuclear assets to rate base, which are more risky than hydroelectric assets. In addition, while operating risks of the hydroelectric business are expected to remain at current levels, these risks are expected to increase for the nuclear business in the 2017-2021 payment period supporting a higher common equity ratio.

The Company's risk profile is further affected by the increased forecasting and financial risks associated with the Company's proposed IR plans and longer rate setting periods, as well as recovery risks associated with both anticipated nuclear rate smoothing deferrals and pension and

<sup>3</sup> EB-2013-0321, Decision with Reasons, at 114.

other post-employment benefit (“OPEB”) costs. Based on the above, Concentric’s opinion is that the appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board in the EB-2013-0321 rate proceeding.

In terms of the comparable return requirement of the fair return standard, the range of common equity ratios for comparable utilities is 40.27% to 54.29%, with an average equity ratio of 49.06% and a median of 49.95%. OPG’s current equity ratio of 45% is on the low end of the comparable group despite its elevated level of risk relative to the proxy group. Specifically, with its significant nuclear concentration, as well as its status as the only company in the group that is a pure generating company, OPG falls toward the upper end of the risk spectrum. Thus, given OPG’s elevated risk relative to the average level of risk faced by the proxy group, Concentric believes the proxy group average and median equity ratios of approximately 49% to 50% provide a floor for the consideration of an appropriate equity ratio for the Company for the 2017-2021 period.

Concentric also finds that an equity ratio of at least 49% will be: (1) more supportive of OPG’s financial integrity and access to capital; (2) consistent with the requirements of the fair return standard, and (3) beneficial to customers. Specifically, an increase in OPG’s equity ratio from its current 45% to 49% will increase cash flow to the Company, bettering its financial stability and strengthening the metrics that the ratings agencies evaluate when assigning credit ratings. Financial stability and strengthened cash flow benefit all stakeholders of the Company, both by maintaining the financial health of the utility, and by supporting its credit rating.

Lastly, while OPG’s risk level is at the upper end of the risk spectrum, Concentric finds that an equity ratio at or above the proxy group average (rather than high end of the range) is appropriate.

In summary, given the material increase in risks since EB-2013-0321, Concentric recommends an equity ratio of no less than 49% be set in the upcoming proceeding, based on the following factors:

- The change in the nuclear to hydroelectric asset mix
- The increase in OPG’s business risk driven by the DRP
- Plans to pursue extended Pickering operations beyond 2020 and the aging of the Pickering plant
- The move to IR for hydroelectric rate-setting and to long-term rate-setting periods for nuclear operations
- The recovery risks associated with pension and OPEB costs and revenue deferred under rate smoothing
- OPG’s higher risk relative to comparable firms that have a median equity ratio of almost 50%

SECTION 2:

## **SCOPE OF ANALYSIS AND OVERVIEW OF CONCENTRIC**

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### **SCOPE**

Concentric was retained to prepare this independent report as to whether the application of the cost of capital approved by the Board in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and hydroelectric payment amounts in OPG's next rate application. Concentric's analysis specifically focused on OPG's capital structure. In preparing this report, Concentric performed the following assessment:

1. Examined the Board's decisions in EB-2007-0905, EB-2010-0008, and EB-2013-0321 to understand the Board's analysis and findings in past cases regarding OPG's cost of capital;
2. Analyzed OPG's business risks since EB-2013-0321 and on a forward-looking basis consistent with how an investor would analyze OPG's risk profile;
3. Examined the capital structures of a proxy group of comparable companies; and
4. Determined an appropriate capital structure for OPG.

### **OVERVIEW OF CONCENTRIC**

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised energy industry participants on the purchase and sale of nuclear facilities, hydroelectric facilities, and other generation assets, and we have served in an independent monitoring or project advisory function on major capital projects at several nuclear generating units in North America. Concentric also has experience relating to major refurbishment work on life cycle management and extended power uprates in the U.S. and Canada. In addition, Concentric has provided expert testimony on the cost of capital in more than 65 regulatory proceedings in Canada and the U.S. over the past five years.

James Coyne, Senior Vice President at Concentric, and Daniel Dane, Assistant Vice President at Concentric, coauthored this report with assistance from other Concentric staff. Mr. Coyne is a senior expert who provides testimony before Canadian provincial and U.S. federal and state agencies on matters pertaining to economics, finance, and public policy in the energy industry. He regularly advises utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes determining the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, demand side management, low-income programs, fuels and power markets. He has advised both buyers and sellers in numerous transactions involving hydroelectric, nuclear, fossil and renewable generation facilities, and worked with companies to develop strategies for acquiring these assets. He has testified or

provided expert evidence before state, provincial and federal jurisdictions across Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions and staff.

Mr. Coyne is also a frequent speaker and author of articles and white papers on the energy industry. Recently, on behalf of the Canadian Gas Association and the Canadian Electric Association, he prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, he facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. In collaboration with the Canadian Gas and Canadian Electric Associations, he publishes a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. He has been an invited speaker for several CAMPUT events including the recent Energy Regulation Course at Queen's University where he spoke on "Innovations in Utility Business Models and Regulation," and will speak in May on North American cost of capital issues. Mr. Coyne also coauthored a report titled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Dane that was prepared for the OEB in June 2007.

Prior to joining Concentric, Mr. Coyne was Senior Managing Director in the Corporate Economics Practice for FTI/Lexecon, and Managing Director for Arthur Andersen's Energy & Utilities Corporate Finance Practice. In those positions, he provided expert testimony and advisory services on mergers, acquisitions, divestitures and capital markets for clients in the energy industry. Previously, he was Managing Director for Navigant Consulting, with responsibility for the firm's Financial Services practice, Director in DRI/McGraw-Hill's Electric and Natural Gas practices, and Senior Economist for the Massachusetts Energy Facilities Siting Council, where he analyzed the supply plans and facilities proposals from the state's electric and gas utilities. He also served as State Energy Economist for the Maine Office of Energy Resources. He holds a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire.

Mr. Dane has advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of those assignments have included the determination of the cost of capital. Mr. Dane has also provided expert testimony on regulated ratemaking matters, including the cost of capital, for investor-owned utilities. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the Board, as discussed above. Mr. Dane has provided sell-side support for approximately \$2 billion in generating asset transactions in the U.S., including nuclear generating facilities, and has been a significant contributor to numerous assignments at Concentric involving independent evaluations of nuclear plant construction project commercial strategies, project controls and management oversight, and new power plant development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

Messrs. Coyne and Dane's qualifications are detailed more fully in Appendices B and C.

SECTION 3:

## BACKGROUND

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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."<sup>4</sup> 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,"<sup>5</sup> and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."<sup>6</sup> 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.<sup>7</sup>

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.<sup>8</sup> The Board observed that meeting the fair return standard is not optional; it is a legal requirement.

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<sup>4</sup> EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.

<sup>5</sup> *Ibid*, at 140.

<sup>6</sup> *Ibid*, at 142.

<sup>7</sup> *Ibid*, at 149-150.

<sup>8</sup> EB-2009-0084, Report of the Board, December 11, 2009, at i.

In discussing the application of the fair return standard, the Board made the following observations:<sup>9</sup>

1. The Board notes that the fair return standard expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective;
2. The Board agrees with the National Energy Board which stated that “[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced;”
3. All three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others;
4. The Board reiterates that an allowed return on equity (“ROE”) is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for;
5. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the fair return standard; and
6. The Board questions whether the fair return standard has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the fair return standard in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital.

With respect to capital structure, the Board found that its current policy for all regulated utilities, which was developed in March 1997, continued to be appropriate. The decision in EB-2009-0084 states: “As noted in the Board’s draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.”<sup>10</sup>

The Board also reiterated other policies, including that “the rate setting methodologies used by the Board apply uniformly to all rate-regulated utilities regardless of ownership. The determination of the rate-regulated utilities’ cost of capital is no exception.”<sup>11</sup>

### **EB-2010-0008**

OPG’s generation mix as of EB-2010-0008 was at approximately 38% nuclear and 62% hydroelectric, based on Board-approved rate base for the prescribed facilities (excluding the lesser of nuclear asset retirement costs and unfunded nuclear liability), which was approximately the same as it had been as of EB-2007-0905. In its March 11, 2011 decision in EB-2010-0008, the Board found that “there is no evidence of any material change in OPG’s business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.”<sup>12</sup>

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<sup>9</sup> *Ibid*, at 19-20.

<sup>10</sup> *Ibid*, at 49.

<sup>11</sup> *Ibid*, at 25.

<sup>12</sup> EB-2010-0008, at 116.

In EB-2010-0008, there was a discussion of technology-specific costs of capital and capital structures. Pollution Probe's experts Drs. Lawrence Kryzanowski and Gordon Roberts recommended an equity ratio of 43% for the hydroelectric operations and an equity ratio of 53% for the nuclear operations, premised on OPG retaining its aggregate equity ratio of 47%. The Board found that there was not enough evidence to support technology-specific capital structures, and reaffirmed its findings in EB-2007-0905 that the risks related to nuclear generation are higher than those related to hydroelectric generation.

In addition, while the issue was identified by the Board in the context of technology-specific capital structures, the OEB recognized an emerging issue, noting that "[a]s the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged."<sup>13</sup>

### **EB-2013-0321**

In EB-2013-0321, the Board found that OPG's business risks had changed, pointing to the addition of 48 hydroelectric assets to OPG's regulated assets and the then recently completed Niagara Tunnel Project, as well as a pension and OPEB variance account that was established after OPG's equity thickness was first set in EB-2007-0905. Specifically, the Board found that the addition of hydroelectric assets and the Niagara Tunnel Project, "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."<sup>14</sup>

As a result of these findings, the Board lowered the equity ratio for OPG from 47% to 45%. Specifically, the Board stated, "...[t]he Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."<sup>15</sup>

In addition, the Board found that, at the time of EB-2013-0321, moving to incentive regulation did not significantly increase risks to OPG such that the capital structure should be reset, noting that the capital structure for the Province's electricity and gas distributors had not been reset when they moved to incentive regulation. The Board did note, however, that part of its decision was based on the fact that OPG was not moving to incentive regulation in EB-2013-0321, and that "any potential changes to business risk this may entail could be considered in the incentive regulation proceeding."<sup>16</sup>

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<sup>13</sup> *Ibid.*, at 117.

<sup>14</sup> EB-2013-0321, Decision with Reasons, at 113. Clarification added.

<sup>15</sup> *Ibid.*, at 114.

<sup>16</sup> *Ibid.*

SECTION 4:

## PRINCIPLES FOR A FAIR RETURN

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The Supreme Court of Canada established the principles surrounding the concept of a “fair return” for a regulated company in the *Northwestern Utilities v. City of Edmonton* (1929) (“Northwestern”) case, where the Supreme Court found:

*By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company’s enterprise.<sup>17</sup>*

As stated by Major and Priddle in 2008, this definition remains in full legal effect today.<sup>18</sup>

United States law regarding fair return for utility cost of capital has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court found:

*The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*

The U.S. Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). There the Court described the relevant criteria as follows:

*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock [...] By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

With the passage of time, the fair return standard has been interpreted many times in both Canada and the U.S. In Canada, the National Energy Board (“NEB”) summarized its interpretation of the

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<sup>17</sup> *Northwestern* at 193.

<sup>18</sup> The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications, by The Honourable John C. Major, Former Justice, Supreme Court of Canada, and Roland Priddle, President, Roland Priddle Energy Consulting Inc., Former Chair of the National Energy Board, March 2008, at 4.

“fair return standard” in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its Trans Québec & Maritimes Pipelines Inc. RH-1-2008 Decision, at pp. 6-7.

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*The [NEB] is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*

- *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
- *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*

*In the [NEB]’s view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline’s revenue requirement, result in tolls that are just and reasonable.<sup>19</sup>*

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Similarly, in its EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, the OEB discussed the necessity of adhering to the fair return standard as follows:

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*The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity’s cost of capital.*

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*... all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].<sup>20</sup>*

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Canadian regulatory authorities, including the Board, have also determined that another key principle in establishing a fair return on equity for a regulated utility is the “stand-alone” principle.

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<sup>19</sup> National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

<sup>20</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, at i and 19.

The Board's specific findings with regard to the stand-alone principle for OPG are included above in the summary of EB-2007-0905.

Furthermore, the Board has recognized that the cost of capital is a forward-looking concept. For example, in its decision in EB-2009-0084, the Board referenced a presentation by Dr. Bill Cannon at CAMPUT's 2009 Energy Regulation Conference during which Dr. Cannon explained the forward-looking nature of the cost of capital as follows: "First, it [the cost of capital] is forward looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return."<sup>21</sup> Elsewhere in that same decision, the Board stated: "First, the Board notes that the [Fair Return Standard] expressly refers to an opportunity cost of capital concept; one that is prospective rather than retrospective."<sup>22</sup> In other words, investors establish their return requirements based on expectations regarding economic growth, inflation, interest rates, the market risk premium and other factors affecting future risks and opportunity costs.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the Board has expressed its view that "the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital."<sup>23</sup> Further, the Board has determined that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities." However, the assessment of comparability "does not require that those entities be 'the same'."<sup>24</sup>

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<sup>21</sup> *Ibid*, at 25.

<sup>22</sup> *Ibid*, at 19.

<sup>23</sup> *Ibid*, at 20.

<sup>24</sup> *Ibid*, at 21.

SECTION 5:

## **CHANGES IN BUSINESS AND FINANCIAL RISK SINCE THE EB-2013-0321 DECISION**

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### **INTRODUCTION**

Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. Financial risk relates to a utility's ability to access capital and the effect of management's and economic regulators' decision-making on a utility's credit profile. Financial risk also affects the financial integrity of a utility. Both business and financial risk have a direct bearing on a utility's cost of capital.

The cost of capital is also a forward-looking concept, and utility investors tend to be long-term providers of capital. For those reasons, it is important to not only review OPG's current business and financial risk profile and its consistency or inconsistency with the Company's deemed capital structure, but also to assess how that risk profile has changed and will change going forward. This approach is consistent with the OEB's findings in its EB-2013-0321 decision regarding OPG's capital structure. The Board determined that because the business risk for the Company's regulated operations had changed in the specific payment-setting period in that proceeding, the capital structure should reflect that change.

This section contains an overview and analysis of OPG's business and financial risks, with a focus on how those risks have changed since EB-2013-0321 and how they are forecast to change over the period from 2017 to 2021, which is the specific payment-setting period under review in OPG's upcoming rate case.

To evaluate OPG's business risks, Concentric performed an independent review of the Company and its regulatory environment. That review included: (1) gaining an understanding of OPG's current and forecasted operating plans for its prescribed facilities; (2) evaluating the risks related to the prescribed hydroelectric facilities; (3) evaluating the risks related to the prescribed nuclear facilities, including the Darlington refurbishment project and plans to pursue extended Pickering operations beyond 2020; (4) analyzing OPG's projected rate bases for its nuclear and hydroelectric businesses, and how those rate bases are expected to change relative to one another over the rate-setting period; and (5) gaining an understanding of the Company's planned rate-setting proposals for the upcoming proceeding and how those proposals would affect OPG's business and financial risks over the period to 2021.

Our experience in assessing business and financial risks and the effect on the cost of capital in other regulatory jurisdictions, as well as our prior roles as an independent monitor and advisor to the power industry, informed our review. Our additional experience advising buyers and sellers of generation facilities, including hydroelectric and nuclear facilities, further informs our views on the investor perspective regarding the business risk of these assets. Our evaluation process included a review of investment analyst reports regarding OPG (such as those from credit rating agencies Standard & Poor's Ratings Service ("S&P") and DBRS), relevant industry data such as that provided by the World Nuclear Association, other publicly-available materials such as Ontario's December

2013 Long-Term Energy Plan (“LTEP”), regulatory filings made by the Company, the OPG 2016 to 2018 business plan with financial projections through 2021, the Company’s financial reports, and interviews with OPG subject matter experts.

Concentric concludes in this section that OPG’s overall risk level will increase materially over the period 2017-2021 from its level as of EB-2013-0321, driven primarily by business risks related to the significant project being undertaken to refurbish the Darlington facility, planned extended Pickering operations beyond 2020, the implementation of incentive regulation for the prescribed hydroelectric assets and rate smoothing for the prescribed nuclear assets, longer rate setting periods, and changes in the Company’s regulatory environment. OPG’s financial risks are also expected to increase over the upcoming rate-setting period, as the Company’s debt levels are forecast to increase during the Darlington refurbishment period. Credit metrics are expected to be further pressured by deferral of some revenues to the post refurbishment period.

## COMPANY OVERVIEW

OPG is an electricity generation company established under the *Business Corporations Act* and is wholly owned by the Province of Ontario. As of December 31, 2015, OPG’s regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington) as well as 54 of the hydroelectric generating stations. OPG’s regulated facilities are referred to as the “prescribed” facilities.

Figure 1 provides the relative rate base from the start of OPG rate regulation by the OEB through to the upcoming test period, and includes, for illustrative purposes, estimated rate base in 2026, after the end of the Darlington refurbishment period.<sup>25</sup> Specifically, the figure provides the rate base, in dollars, for both the prescribed nuclear and hydroelectric facilities, and a “hydroelectric-to-nuclear” ratio.

OPG’s common equity ratio, both the historical ratio as well as the ratio proposed in this proceeding, is also provided. As can be seen in the figure, the hydroelectric-to-nuclear ratio peaked during the period for which rates in EB-2013-0321 were set, which was also the period for which the Board lowered OPG’s common equity ratio to 45%. However, starting in 2017, the hydroelectric-to-nuclear ratio is expected to begin to decline significantly. By 2021, *i.e.*, the end of the proposed five-year rate period, the hydroelectric-to-nuclear ratio is expected to be at its lowest point historically, and is expected to continue to decline over the following five years. The average test-period hydroelectric-to-nuclear ratio for 2017-2021 is nearly one-half the ratio for the period for which EB-2013-0321 rates were set.

<sup>25</sup> Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG’s rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

Figure 1: OPG's Prescribed Facilities Rate Base (\$ billions)

	EB-2007-0905 Payment Order		EB-2010-0008 Payment Order		EB-2013-0321 Payment Order		Test Period <sup>26</sup>					End of DRP (Illustrative)
	2008	2009	2011	2012	2014	2015	2017	2018	2019	2020	2021	2026
<b>Hydro</b>	\$3.9	\$3.9	\$3.8	\$3.8	\$7.5	\$7.5	\$7.5	\$7.5	\$7.5	\$7.6	\$7.7	\$7.5B
<b>Nuclear<sup>27</sup></b>	\$2.4	\$2.5	\$2.4	\$2.4	\$2.3	\$2.4	\$3.3	\$3.5	\$3.5	\$7.5	\$8.0	\$13.5B
<b>Test Period Hydro/ Nuclear ratio</b>	158%	157%	159%	161%	325%	319%	227%	214%	214%	101%	96%	56%
<b>Test Period Ratio Avg</b>	159%				322%		171%					56%
<b>Common Equity Ratio</b>	47%	47%	47%	47%	45%	45%	<b>Recommended Minimum</b>					
							49%	49%	49%	49%	49%	

<sup>26</sup> Estimated rate base values pending finalization of OPG's rate application.

<sup>27</sup> Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

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.<sup>28</sup> 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

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<sup>28</sup> 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.

it had been in 2009), Concentric is not aware of any reason why variances in water flow over the rate period are more or less at risk of being higher or lower than at the time of EB-2013-0321. In addition, Concentric is not aware of factors that would materially change the risks related to surplus baseload generation in the test period. Further, OPG has a Hydroelectric Water Conditions Variance Account that records and mitigates the financial impact of differences between forecast and actual water conditions, and a Surplus Baseload Generation Variance Account that records and mitigates the financial impact of surplus baseload generation curtailments (and is applying to continue those accounts in this proceeding). The Hydroelectric Water Conditions and Surplus Baseload Generation variance accounts apply to OPG's six hydroelectric facilities that were regulated prior to EB-2013-0321, as well as 21 of the hydroelectric facilities that were newly regulated as of EB-2013-0321. As such, Concentric is of the view that the risks related to the availability of water to power the stations and surplus generation curtailment have not changed since EB-2013-0321.

Similar to the risks related to the availability of water flows, Concentric is not aware of changes in risks related to environmental regulations affecting hydroelectric power relative to the risk level that has existed in the recent past.

In terms of the need for capital expenditures to address regulatory requirements, while OPG is expecting enhancements to the existing dam safety technical guidelines in the near future, the risk related to these enhancements is not materially different from recent years. In other words, Concentric is not aware of any event or change in regulatory regimes that would lead to a significant departure from past trends in the risks related to implementation of hydroelectric-related regulations.

Regarding OPG's ability to recover hydroelectric costs, including a return in a timely manner, there is a substantial change in risk related to OPG's hydroelectric facilities attributable to the planned transition in the rate setting term from a two-year cost of service to a five-year incentive regulation regime. Risks related to incentive regulation are described below.

OPG is proposing that all currently-approved deferral and variance accounts related to its prescribed hydroelectric facilities remain in place so there is no change in risk in that regard. These include the Hydroelectric Water Conditions Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account (as discussed above).

Concentric concludes that, based on the above, OPG's operational risks related to its prescribed hydroelectric facilities have remained relatively the same since EB-2013-0321, but OPG's regulatory risk related to the hydroelectric facilities is expected to change as a result of the movement to a five-year incentive rate plan, as discussed in a later section.

## **NUCLEAR FACILITIES**

OPG has two prescribed nuclear facilities: Darlington and Pickering. Darlington is a CANDU, four-unit station with a generating capacity of about 3,500 MW. Pickering is a CANDU, six-unit station with a generating capacity of about 3,100 MW. Both facilities feature prominently in Ontario's 2013 LTEP over the 2017-2021 period.<sup>29</sup>

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<sup>29</sup> Ontario's Long-Term Energy Plan, December 2013, at 28-30.

Generally, the major risks to a regulated utility related to nuclear power generation include: (1) the ability to implement large and complex projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Specific to OPG, the Darlington Refurbishment Project presents an incremental source of risk to the Company that will become increasingly significant during the upcoming rate-setting period. That incremental risk is not only related to the execution of the project, but is also due to inherent uncertainty related to its timing and completion, as outlined in the LTEP. While the Province has granted OPG approval to proceed with the first unit refurbishment, OPG is required to seek the Province's approval to proceed with each subsequent unit refurbishment. OPG's plans to pursue extended Pickering operations beyond 2020 also poses considerable risks. In addition, OPG continues to face risks related to the implementation of new safety and regulatory requirements.

OPG's forecasts for nuclear costs and generation levels are being made in the face of this uncertainty, while also covering a longer, five-year term under the Company's ratemaking proposals, subject to a proposed mid-term review, discussed below.

#### A. Darlington

OPG is planning to refurbish Darlington for 30 additional years of operations. In terms of the DRP, the four-unit refurbishment project is a megaproject with a budget of \$12.8 billion including interest and escalation,<sup>30</sup> lasting approximately a decade. For OPG, the DRP is a significant undertaking, as the \$12.8 billion cost of the project represents over 100% of OPG's total regulated rate base as of EB-2013-0321 (*i.e.*, the rate base most recently approved by the Board), and approximately 70% of OPG's overall net in-service property, plant and equipment ("PP&E") balance (both prescribed and non-regulated). Relative to the size of the Company, the DRP is one of the most significant undertakings in the North American nuclear industry in the recent past. For context, Figure 2 below provides a comparison of the size of the DRP relative to OPG's size to the size of two other nuclear megaprojects that are currently ongoing in North America relative to their owners' sizes.

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<sup>30</sup> OPG, "Refurbishment of the Darlington Nuclear Generating Station. An Impact Analysis on Ontario's Economy," November 2015.

Figure 2: DRP as a Percentage of OPG's Net Assets, Compared to Two other North American Nuclear Megaprojects

	Darlington Refurbishment Project (OPG)	V.C. Summer New Nuclear Plant (SCANA Corporation) <sup>31</sup>	Vogtle New Nuclear Plant (Southern Company) <sup>32</sup>
Estimated Cost	\$12.8b	\$6.85b (US)	\$7.5b (US)
Sponsor Net In-service PP&E	\$20.6b <sup>33</sup>	\$12.7b (US)	\$58.2b (US)
Estimated Cost / Net PP&E	62%	54%	13%

A project of the DRP's size and schedule length, regardless of the technology, that will more than double the Company's rate base, inherently presents a significant source of risk for any utility. As noted in the Scope of Analysis and Overview of Concentric section of this report, Concentric has been an advisor to several North American utilities undertaking megaprojects such as the DRP. We have witnessed firsthand the issues even the most well planned large construction projects can face, including scope, budget, and schedule increases, as well as increased regulatory scrutiny. The performance of large construction projects in a nuclear setting compounds those issues.

Specifically, the DRP will include multiple complex work packages, including the removal and replacement of the reactor calandria tubes and pressure tubes from each reactor, replacement of all feeders, refurbishment of the existing fuel handling equipment, refurbishment of the existing turbine generators, refurbishment of the existing steam generators, and a set of supporting refurbishment projects aligned with existing station systems. The project will involve numerous third-party vendors and the coordination of multiple scopes of work, all within the highly regulated and safety-conscious environment of a nuclear facility. In addition, the Canadian marketplace for nuclear construction firms is limited, increasing the risks related to vendor management and performance.

The inherent risks related to an undertaking of the DRP's magnitude are significant. As noted in the construction industry handbook "Industrial Megaprojects: Concepts, Strategies, and Practices for Success:"

*As the projects have increased in size and complexity, they have become much more difficult to manage. Cost overruns, serious slips in completion schedules, and operability problems have all become more common.*<sup>34</sup>

The Company does employ robust risk mitigation strategies related to the DRP. For instance, the LTEP requires adherence to risk-mitigating principles that include off-ramps<sup>35</sup> and all major

<sup>31</sup> Amounts shown are for SCANA Corporation's 55% share in the V.C. Summer plant only. Sources: "Costs and Deadlines Continue to Challenge V.C. Summer Nuclear Plant Project," Power, August 19, 2015. SCANA Corporation SEC Form 10-Q for the period ended September 30, 2015.

<sup>32</sup> Amounts shown are for Southern Company's 45.7% share in the Vogtle plant only. Sources: "No new cost overruns at Vogtle nuclear plant," Times Free Press, September 3, 2015. Southern Company SEC Form 10-Q for the period ended September 30, 2015.

<sup>33</sup> OPG, 2015 Consolidated Financial Statements, at 7.

<sup>34</sup> Merrow, Edward W., "Industrial Megaprojects: Concepts, Strategies, and Practices for Success," John Wiley & Sons, Inc., 2011, at 12.

<sup>35</sup> Ontario's Long-Term Energy Plan, December 2013, at 29.

contracts executed by OPG for the DRP contain suspension and termination provisions.<sup>36</sup> In general, OPG has approached the project strategically and methodically, including performing numerous front-end loading activities to plan and prepare for the DRP, such as completion of detailed designs and construction of a full-scale model training reactor. In addition, the recent changes to O. Reg. 53/05 provide some reduction to future recovery risk by establishing the overall need for the DRP in the regulatory context.<sup>37</sup> However, notwithstanding the above, in Concentric's opinion, significant inherent risks associated with the DRP remain. These risks cannot be fully offset by mitigation strategies.

Importantly, there is no model of a successfully implemented commercial strategy for OPG to follow with regard to the DRP, as prior CANDU refurbishments have encountered significant challenges. As demonstrated by those prior projects, project schedules can slip, outage durations can be different than expected, and there are risks related to the performance and output of the nuclear facilities post-refurbishment. In addition, while OPG has carefully planned its commercial and contracting strategies for the DRP, the Company does remain at risk related to the performance of project contractors and suppliers. Lastly, the size and schedule length of the DRP are subject to changes in economic, regulatory, and political assumptions underlying the project, putting the Company at risk of not recovering its full investment.

In addition, as discussed in further detail below, OPG also faces an increase in risk related to its rate-setting proposal for prescribed nuclear facilities. That proposal, and in particular its revenue deferral elements, is driven in part by the overall anticipated size and cost of the DRP.

Apart from the DRP, OPG also faces increased risks due to degradation of Darlington's primary heat transport pump motors. Failure of the motors could lead to unexpected downtime and loss of generation from Darlington. While the Company has started to replace and/or refurbish the motors, the risks related to their degradation will persist until the replacement program is completed.

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<sup>36</sup> OPG, 2015 Consolidated Financial Statements, at 21.

<sup>37</sup> Ontario Regulation 53/05, Payments under Section 78.1 of the Act, as amended on January 1, 2016.

## B. Pickering

OPG has announced its intention to pursue extension of Pickering operations beyond 2020 to 2024, and has received the Government of Ontario's approval to do so.<sup>38</sup> Specifically, OPG plans to operate all six operating Pickering units until 2022, at which point two units would be shut down, and the remaining four units would operate through 2024. Approval from the Canadian Nuclear Safety Commission ("CNSC") is also required, expected through a relicensing process in 2017/2018, as is approval by the OEB for cost recovery of the cost and production impacts. Incremental OM&A expenses of approximately \$300 million and additional outage days reducing production will be required during the upcoming rate period, through 2020, to enable extended Pickering operation. OPG's current operating license for the Pickering station expires on August 31, 2018, and OPG is required to notify the CNSC by June 30, 2017 of the end date of commercial operation for all operating Pickering units. There are risks associated with the re-licensing of the units to the end of the planned extended operation period.

Risks associated with OPG's plans for Pickering extended operations principally include the risk that there is a future determination that extended operation of the plant is not feasible, if, for instance, it is determined that the fuel channels (the life limiting components of a CANDU reactor) or another major component or system cannot support operations through 2024. If Pickering were to cease operation before 2024, OPG may be at risk for recovery of the expenditures incurred to enable extended operation and for foregone production. The main risk reducing factors include the fact that, through extended operation, OPG has more time to plan for the eventual retirement of the plant, and the additional cash flow to the Company from continued Pickering generation during the DRP period.

Life extension at Pickering puts OPG much in the same situation that it faced as of EB-2013-0321 in terms of the planned remaining operational life of the facility. Namely, as of EB-2013-0321, OPG was planning to retire Pickering in 2020 (*i.e.*, approximately seven years hence), a timeframe similar to what the Company is planning for now. However, Pickering is now older than it was as of EB-2013-0321, which increases reliability concerns including potential discovery of unexpected conditions and increases risks related to production loss and revenue recovery. In fact, no other CANDU plant has operated as long as the planned life of Pickering. These factors indicate that, on balance, risks related to Pickering operations have increased since EB-2013-0321.

## C. Nuclear Regulation and Safety Requirements

The nuclear industry is in an unprecedented era related to the introduction and required implementation of new safety requirements. This era was launched by the earthquake and tsunami that affected Japan on March 11, 2011, causing significant damage to the Fukushima Daiichi nuclear complex. The safety requirements are likely to continue to impact the nuclear industry, both internationally and in Canada. In addition, such regulations and safety requirements are not limited to earthquake protection at nuclear plants, but also include such factors as security enhancements, storage of spent fuel, fire protection, and cybersecurity. As the Chief Nuclear Officer at U.S. utility Xcel Energy recently stated in testimony before the Minnesota Public Utilities Commission:

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<sup>38</sup> OPG Press Release, "OPG Ready to Deliver Refurbishment of Darlington Nuclear Station; OPG also Planning Continued Operation of Pickering Station," January 11, 2016.

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*It is important to recognize that the nuclear industry (including Xcel Energy) is in the heart of the biggest regulatory implementation of NRC rules ever witnessed... These rules translate into mandated compliance work for us resulting from the incident at Fukushima (including flooding and seismic analysis), fire protection, used fuel storage, plant security, and "hardening" the grid for protecting both the regional system and our plants.<sup>39</sup>*

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Specific to the nuclear industry's response to the accident at Fukushima, SNL Financial noted in a recent article that the "work is hardly done" with regard to the implementation of Fukushima-related measures.<sup>40</sup> The article further cited a representative from the U.S. Nuclear Energy Institute, an industry policy organization, as stating that cost estimates to respond to new NRC rules are "hard to predict [or make] an educated guess at this point."<sup>41</sup>

In Canada, there is similar uncertainty with regard to the final size, scope, and timing of plant modifications, design changes, and licensing/regulatory requirements to maintain compliance with the industry's reaction to Fukushima and other safety and regulatory requirements. While the CNSC has made its recommendations for changes in the industry and closed out its Fukushima-related action items for OPG specifically, the risk remains for additional requirements as the CNSC evaluates nuclear plant owners' implementation of their Fukushima-related projects and adopts any additional safety standards being developed in the industry, both in Canada and internationally. Examples of recent evolving requirements of the CNSC include new hold points on pressure tubes, a requirement for multi-unit probabilistic safety assessments, and a requirement to distribute potassium iodide pills to residents in proximity of nuclear facilities.

#### D. Conclusion Regarding Nuclear Facilities

Concentric's opinion is that the operational business risks related to OPG's prescribed nuclear facilities have increased since EB-2013-0321, and will continue to increase over the 2017-2021 period. In particular, the risks posed by the DRP, plans for extended Pickering operation, increasing risks associated with degradation of aging station components, and the nuclear industry's evolving response to increasing safety and regulatory requirements subject the Company to both heightened cost and generation related risk. The risks related to the Company's anticipated rate proposals in the upcoming rate proceeding, which further contribute to higher overall business risk, are discussed in a later section.

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<sup>39</sup> Direct Testimony and Schedules of Timothy J. O'Connor before the Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, November 2, 2015.

<sup>40</sup> SNL Financial, "NRC prepares to vote on 'centerpiece' of post-Fukushima nuke plant regulations," August 17, 2015.

<sup>41</sup> *Ibid.*

## GENERATION MIX

With the expansion of OPG's regulated nuclear business due to the DRP, nuclear generation is projected to comprise a comparatively larger portion of OPG's overall regulated rate base. As previously noted, the Board has recognized that nuclear assets are higher in risk than hydroelectric assets. The relative increase in nuclear assets as a percentage of rate base by the end of the upcoming rate period to 2021 indicates that, all else being equal, OPG will become more risky over time.

Specifically, the Company's prescribed generation mix is projected to change over the 2017-2021 period, with a significant increase in nuclear rate base since EB-2013-0321 due in large part to the DRP, as shown in Figure 1. OPG's hydroelectric business risk level will remain relatively the same over the upcoming rate period, other than the transition to a five-year IR plan, while nuclear risks are expected to increase on a number of fronts.

In support of its findings in EB-2013-0321 that OPG's business risk had changed between EB-2010-0008 and EB-2013-0321, the Board cited the "increase [in the] proportionate share of rate base related to hydroelectric facilities from about half to approximately two-thirds now [*i.e.*, as of EB-2013-0321],"<sup>42</sup> while noting that the "relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings."<sup>43</sup> By the end of the upcoming rate period, nuclear rate base is projected to be 51% of OPG's total prescribed generation rate base, as compared to 24% at the end of the current rate period (for reference, nuclear rate base comprised less than 40% of total prescribed rate base during the period in which OPG's deemed equity ratio was 47%). By the end of 2026, OPG estimates its nuclear rate base to be approximately 64% of total generation rate base, significantly higher than any time following the inception of OEB's regulation of OPG in 2008. This, coupled with the increase in nuclear-specific risks discussed above, indicates an increase in OPG's overall business risk level for its regulated operations, which Concentric concludes supports an increase in OPG's deemed equity thickness.

## OPG'S RATE PROPOSALS<sup>44</sup>

Since April 1, 2008, OPG has operated under cost-of-service regulation, which is the traditional framework under which regulated utilities' rates are set. Under cost of service regulation, rates are set on the basis of a defined forward-looking test period, typically one or two years. Rates are not set again until the next rate case, in which the cost of service is re-established based on current conditions and forecasts. If costs begin to or are forecast to materially change from levels established in the last rate case, a new rate proceeding provides the opportunity to reflect those changes. There will, however, be regulatory lag until costs are adjusted, thereby affecting the utility's cash flows and earnings (positively or negatively) during this interim period, subject to any authorized deferral and variance accounts.

<sup>42</sup> EB-2013-0321, Decision with Reasons, at 113.

<sup>43</sup> *Ibid.*

<sup>44</sup> Concentric's analysis of regulatory risk assumes continuation of all applicable existing Deferral and Variance accounts for both OPG's prescribed hydroelectric and nuclear facilities during the 2017-2021 period, as planned as part of OPG's rate proposal. Business risk for OPG would be higher than currently assumed by Concentric if some of these accounts are not approved.

Some regulators have approved incentive regulation mechanisms or performance-based regulation (“PBR”) plans, which, to various degrees, decouple the setting of rates/revenue from utilities’ costs. Concentric is of the view that IR and PBR frameworks can create additional risk for utilities. In its “Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,” the Board expressed a view that “[PBR] provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies.”<sup>45</sup> Competitive companies are subject to a greater amount of risk than traditionally rate-regulated companies, in that competitive companies bear the incremental risk of profits significantly declining from expected levels, while having a greater opportunity to accrue profits that are over and above expectations. Those companies generally have lower credit ratings than OPG and higher costs of capital.

In assessing regulatory risk for the utilities sector, DBRS has indicated that it views incentive regulation as higher risk than cost-of-service regulation. This is consistent with Concentric’s opinion regarding OPG’s planned rate proposals. In addition, DBRS considers the length of an incentive regulation period, and assigns higher risk to longer incentive regulation mechanism periods.<sup>46</sup> Figure 3 shows how DBRS assigns rankings based on the method of rate regulation (*i.e.*, cost of service vs. incentive regulation).

Figure 3: DBRS Ranking Criteria: Cost of Service vs. Incentive Regulation<sup>47</sup>

Score	Item	Definition
Excellent	Cost of Service	<ul style="list-style-type: none"> <li>COS regime allowing utilities to recover prudently and reasonably incurred operating costs</li> </ul>
Good	IRM (3 years or shorter)	<ul style="list-style-type: none"> <li>IRM regime with maximum three years between the COS years</li> <li>For an IRM period of more than three years, there are reasonable mechanisms in place to mitigate unexpected capital investment and operating costs. In addition, key IRM assumptions, including CPI and productivity factors, are reasonable</li> </ul>
Satisfactory	IRM (4-5 year framework)	<ul style="list-style-type: none"> <li>The IRM period is four to five years</li> </ul>
Below Average	IRM (6-10 year framework)	<ul style="list-style-type: none"> <li>The IRM period is six to ten years</li> </ul>
Poor	IRM (10+ years)	<ul style="list-style-type: none"> <li>The IRM period is over ten years</li> </ul>

In this proceeding, based on the Board’s expectation, OPG plans on making key ratemaking proposals that, if accepted by the Board, will have material effects on the Company’s risk profile. Specifically, for the prescribed hydroelectric facilities, OPG expects to propose an incentive

<sup>45</sup> Report of the Board, “Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,” October 18, 2012, at 10, citing RP-1999-0034, Decision with Reasons, January 18, 2000.

<sup>46</sup> DBRS, “Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry,” October 2015, at 13.

<sup>47</sup> *Ibid.*

regulation plan based on a price cap index with coverage of both capital and OM&A. The incentive regulation plan will be proposed for a term of five years (2017-2021) and does not include a proposal to rebase costs in 2017. As a result, costs last approved by the OEB in 2014 will provide the basis for OPG's payment amounts through 2021. Under the proposed hydroelectric IR plan, OPG will be exposed to the risk that costs deviate from the price cap over the five-year rate period. In addition to the decoupling of revenues from costs, the hydroelectric IR plan will differ from OPG's traditional regulatory framework in that rates will be established for a five-year period, whereas, OPG's cost of service rates have traditionally been set for significantly shorter periods of time (two years or less).

For the prescribed nuclear facilities, the Company plans to propose a five-year Custom Incentive Regulation plan. OPG is aligning its proposal with the principles of the Renewed Regulatory Framework as required by the OEB in its letter of February 17, 2015.<sup>48</sup> The proposal is expected to include all of OPG's nuclear costs and forecast production, with an additional stretch factor reduction in certain elements of OPG's forecast revenue requirement to provide additional incentives for cost performance improvements.

OPG is also planning a rate smoothing proposal that involves deferring recovery of a substantial portion of the OEB-approved revenue requirement until after the end of the DRP in a Rate Smoothing Deferral Account established by O.Reg. 53/05, which will track the difference between the Board determined smoothed payment amount and OPG's Board-approved revenue requirement. OPG's rate-setting proposal is expected to be for a five-year (2017-2021) period. OPG also plans on requesting a mid-term review to identify any forecast changes in production and related fuel costs for the period July 1, 2019 to December 31, 2021. Differences between the applicable forecast approved by the OEB in the upcoming proceeding and such forecasts for the period July 1, 2019 to December 31, 2021 approved by the OEB during the mid-term review would be recorded in a proposed variance account. Like the proposed hydroelectric IR plan, OPG's proposed rate-setting plan for the prescribed nuclear facilities will expose the Company to incremental risks related to costs deviating from expectations for longer periods than its historical two-year cost of service-based rate plans as well as risks in achieving the additional stretch factor reduction in the revenue requirement.

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.

## FINANCIAL RISK

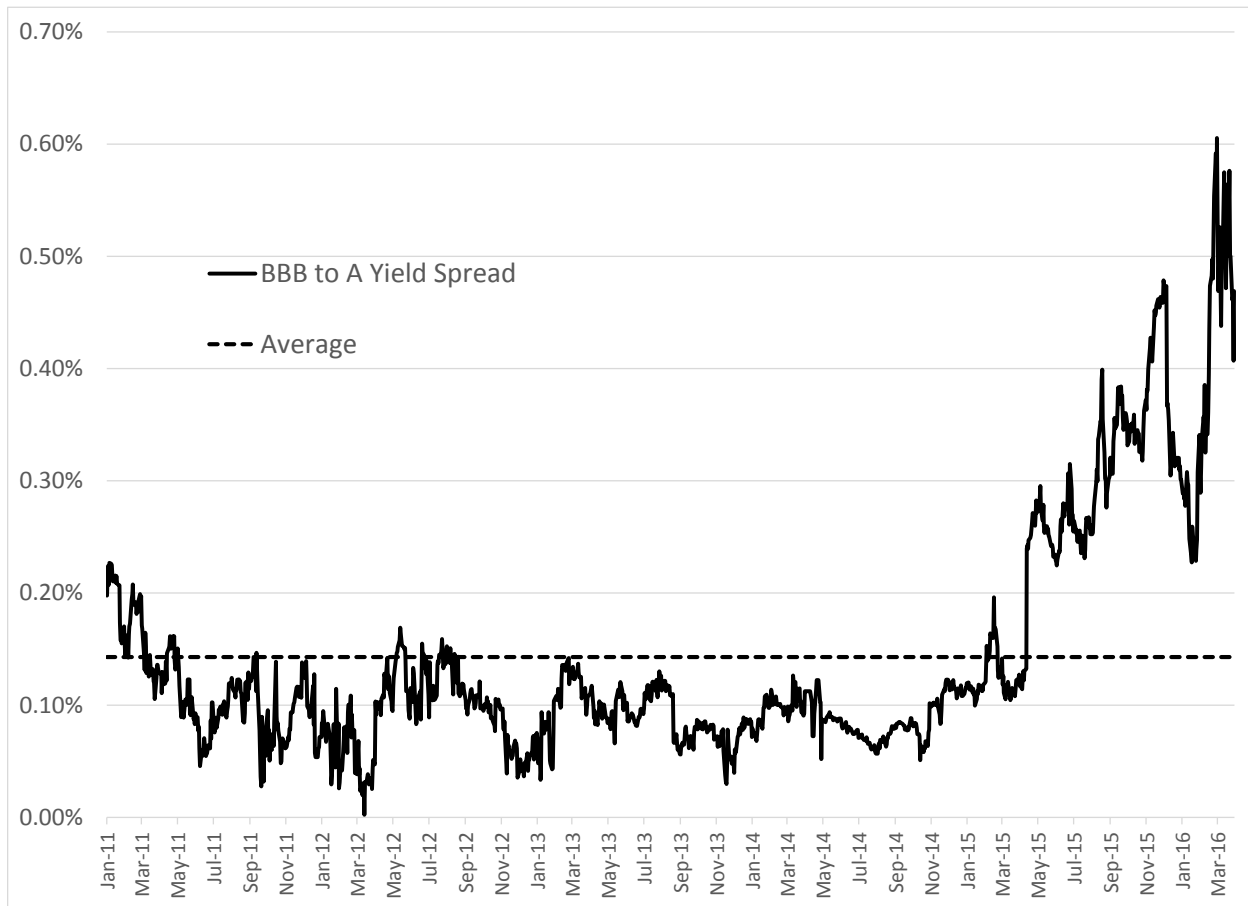
Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Financial risk also relates to a utility's ability to access capital and the effect of management and regulatory decision-making on a utility's credit profile. In developing an assessment of a regulated utilities' financial risk profile, credit rating agencies view financial risk as an important consideration. Specifically, S&P states:

<sup>48</sup> The Board expects OPG to develop an IR framework for its hydroelectric assets, and a custom IR framework for its nuclear assets based on the principles outlined in the RRFE.

*The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.<sup>49</sup>*

Having adequate cash flows to support or improve a utility's credit rating benefits all utility stakeholders. There is a direct link between a utility's credit rating and its cost of borrowing, as well as its ability to access capital in difficult financial settings. Figure 4, below, provides the historical spread between A-rated and BBB-rated Canadian utility bonds, which on a 30-day average basis is currently above 50 basis points (*i.e.*, 0.50%), well in excess of the five-year average.

Figure 4: Spread between Canadian BBB and A Utility Bond Yields



The magnitude of the DRP, with \$12.8 billion in capital expenditures, will pose significant risks to OPG's ability to earn its authorized return and maintain credit metrics that support the Company's credit rating over the short to medium term. In particular, OPG's credit metrics are expected to be

<sup>49</sup> Standard & Poor's Ratings Services, "Corporate Methodology," November 19, 2013, at 3.

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:

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*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.<sup>50</sup>*

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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.<sup>51</sup> 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.<sup>52</sup> The OEB noted the disposition of that account would be informed by the outcome of a future generic proceeding.<sup>53</sup> 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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<sup>50</sup> 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.

<sup>51</sup> 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.

<sup>52</sup> EB-2013-0321, Decision with Reasons, at 88-89.

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

the OEB issued a letter opening a consultation on rate-regulated pensions and OPEBs, the objectives of which are to:

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*[D]evelop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications that will be incremental to current filing requirements, and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated entities.<sup>54</sup>*

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At the time of writing, the consultation is currently ongoing.

Based on the above, the Company is at risk of non-recovery for close to \$450 million (*i.e.*, the cumulative forecast difference between the cash and accrual basis of accounting for pensions and OPEBs by the end of 2016).

In addition, as identified in the Company's initial written submission in the above consultation, OPG would face the potential of charging significant amounts to other comprehensive income related to the write-off of pension and OPEB-related regulatory assets if it is required to maintain the rate recovery of pension and OPEB expenses on a cash basis with no cash-to-accrual variance account. Moreover, if the Company is impeded in the future in its ability to recognize regulatory assets related to the timing differences between cash and accrual accounting for pension and OPEB costs, it would result in lower net income for a number of years, compared to the existing recovery methodology that includes a cash-to-accrual variance account. If that were to happen, it would weaken the Company's credit metrics and increase the financial risk of OPG.

Based on those two factors (*i.e.*, pressure on cash flows due to nuclear rate smoothing and the potential permanent switch to recovery of pension and OPEB costs on a cash basis), Concentric finds that OPG's financial risk level has increased since EB-2013-0321.

## **CONCLUSION REGARDING CHANGES IN BUSINESS AND FINANCIAL RISK SINCE EB-2013-0321**

Concentric concludes that OPG's overall risk level will increase over the period 2017-2021 from its level as of EB-2013-0321, driven by business risks related to the DRP, pursuit of extended Pickering operation, increasing risks associated with degradation of aging nuclear station components, the implementation of incentive regulation, and changes in the Company's regulatory treatment, among other factors. Increased financial risks, including those arising from OPG's rate-setting proposal for its prescribed nuclear facilities and risks related to future recovery of Pension and OPEB accrual costs will negatively affect the Company's credit metrics, leading to additional financial risks relative to prior risk levels. Concentric's opinion is that an appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board prior to the EB-2013-0321 rate proceeding.

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<sup>54</sup> May 14, 2015 letter from the Ontario Energy Board to Ontario's regulated utilities regarding "Consultation on the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs Board File Number EB-2015-0040."

SECTION 6:

## COMPARATIVE ANALYSIS

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In addition to assessing changes to OPG's business and financial risk profile since EB-2013-0321, Concentric has also analyzed the equity ratios of other utilities screened for risk characteristics similar to OPG's risk characteristics. A review of equity ratios authorized at similarly situated regulated utilities provides context for where, within a reasonable range, OPG's equity ratio should be set by the Board. Our analysis of comparable regulated utilities with significant regulated generation assets indicates that OPG's current equity thickness is low relative to comparable companies, despite OPG falling towards the upper end of the spectrum of risk profiles established by the proxy companies. The authorized equity ratios of the proxy companies range from 40.27% to 54.29%, with an average of 49.06% and a median of 49.95%.

### USE OF PROXY COMPANY ANALYSIS IN MAKING COST OF CAPITAL DETERMINATIONS AND IN BENCHMARKING RISK

Analyses of comparable, or "proxy," companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities and for benchmarking business and financial risks. Proxy groups are used for the following main reasons in cost of capital determinations: (1) adherence to the comparable investment standard; (2) since the cost of capital is a market-based concept, and given that OPG is not a publicly-traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of the cost of capital evaluation process; and (3) even if OPG's regulated operations were held by a stand-alone publicly traded entity, it is possible that transitory events could bias its market-determined cost of capital in one way or another over a given period of time. A significant benefit of using a proxy group is its ability to mitigate the effects of anomalous events that may be associated with any one company.

Regulatory commissions and cost of capital analysts generally apply a set of screening criteria in order to define a risk-appropriate group of comparable companies. For instance, the Federal Energy Regulatory Commission ("FERC") provides the following summary of its practice for selection of a proxy group for electric transmission companies:

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**Composition of the Proxy Group:** *In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no*

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*major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*<sup>55</sup>

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While the individual screens require modification based on the subject company to which proxy companies are being compared,<sup>56</sup> the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence the analyst can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of electric utility companies that are risk appropriate for comparison to OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range.

At issue, then, is how to determine an appropriate equity ratio in the context of that range. That determination must be based on an assessment of the company-specific risks relative to the proxy group and the informed judgment and experience of the analyst. As such, it is incumbent on the analyst to apply judgment to determine where, within a range of equity ratios determined by use of a proxy group, the subject company (in this case, OPG), falls. For example, the NEB, in discussing the cost of capital for the TransCanada Mainline, stated, “[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences.”<sup>57</sup> In other words, whereas a subject company of average risk relative to the proxy group could warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk could warrant an equity ratio above the mean or median result, and a company of lower risk could warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is a common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG’s capital structure. In the discussion that follows, we present Concentric’s analysis of OPG’s level of business and financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, OPG’s equity ratio should be set by the Board.

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<sup>55</sup> Opinion No. 531, *Order on Initial Decision*, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45.

<sup>56</sup> For instance, the FERC applies a screen for the inclusion of master limited partnerships (“MLPs”) in natural gas pipeline proxy groups that the MLPs derive at least 50% of operating income from, or have 50% of their assets devoted to, interstate operations (see, Opinion No. 510, *Portland Natural Gas Transmission System*, 134 FERC ¶ 61,129 (February 17, 2011), at 62.

<sup>57</sup> National Energy Board RH-003-2011 Reasons for Decision, *TransCanada PipeLines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd.*, March 2013, at 165.

## SELECTION OF PROXY COMPANIES

As a starting point for our screening process, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Canadian Utilities Limited, Emera Inc. (“Emera”), Enbridge Inc., Fortis Inc. (“Fortis”), and TransCanada Corporation, and the 46 U.S. companies that Value Line classifies as “Electric Utilities”.<sup>58</sup>

From that group, Concentric screened for companies that:

1. **Own regulated generation assets that are included in rate base.** As it relates to the rate setting process, OPG’s assets represent 100% rate-regulated generation. As such, it is important to exclude companies from the proxy group that bear no risks related to regulated generation. The reason for this is the generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody’s Investors Services in its 2013 ratings methodology for regulated electric and gas utilities, “[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility’s infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;”<sup>59</sup>
2. **Own regulated nuclear and/or hydroelectric generation.**<sup>60</sup> As noted earlier, OPG’s rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as previously noted, the Board has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities.
3. **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company.** This screen, in combination with the screen below regarding electric revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated, electric operations. While rates in this proceeding are being set for OPG’s 100% rate-regulated operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their revenues and net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a “bright line” percentage for separating regulated from non-regulated companies, in Concentric’s experience, using a screening criteria of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group;

<sup>58</sup> Precedent for the consideration of U.S. proxy companies in Canadian cost of equity analyses is discussed in Appendix A.

<sup>59</sup> Moody’s Investors Services, Rating Methodology: Regulated Electric and Gas Utilities,” December 23, 2013, at 23.

<sup>60</sup> Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation.

4. **Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations.** Including only those companies that derive more than 80% of their regulated revenue and net income from regulated electric operations ensures that the proxy companies, like OPG, derive the predominant share of their revenues and operating income from their regulated electricity segments. Similar to the regulated revenue and net income screen, the 80% regulated electric revenue and net income screen is not a "bright line," but rather balances the comparability of the proxy group with its overall size; and
5. **Have an investment grade credit rating similar to that of OPG.** As noted earlier, OPG has an "A (low)" issuer and unsecured debt rating from DBRS, and a "BBB+" corporate credit rating from S&P. In addition, as noted earlier, S&P 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. Credit ratings are based on the utility's business risk profile (which includes an assessment of the regulatory environment in which the utility operates) and its financial risk profile. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."<sup>61</sup> Concentric's credit rating screen selects electric utility companies with investment-grade credit ratings. Selecting a proxy group of similar risk electric utility companies with investment-grade credit ratings minimizes the need to adjust the results to account for perceived differences in business or financial risk between those companies and OPG. Further, selecting proxy companies that, like OPG, have an investment grade credit rating (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above) ensures that the proxy companies are generally in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.

None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Fortis, Inc. ("Fortis") only failed the screens that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company's regulated operations and that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Specifically, Emera currently owns no regulated hydroelectric or nuclear generation, and Fortis has 63% regulated electricity revenue and 62% regulated net income, while only owning a minimal amount of regulated hydroelectric generation (and no nuclear generation). In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera and Fortis in the proxy group, as they otherwise meet our screening criteria. Figure 5 presents the eighteen U.S. companies that met our screening criteria, along with OPG and the two Canadian companies noted above. In addition to the company name, Concentric also provides the S&P rating,

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<sup>61</sup> See, for example, Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.

as well as S&P's business risk and financial risk rating summary for each company. Exhibit 1 details how each proxy company meets the screening criteria above.

Figure 5: North American Electric Utility Proxy Group and OPG

Company	Ticker	S&P Ratings Summary – Credit Rating/ Outlook	S&P Ratings Summary – Business Risk	S&P Ratings Summary – Financial Risk
<b>OPG</b>	--	<b>BBB+/Stable</b>	<b>Strong</b>	<b>Aggressive</b>
ALLETE, Inc.	ALE	BBB+/Stable	Strong	Significant
Ameren Corporation	AEE	BBB+/Stable	Excellent	Significant
American Electric Power Company, Inc.	AEP	BBB/Positive	Strong	Significant
Duke Energy Corporation	DUK	A-/Negative	Excellent	Significant
Edison International	EIX	BBB+/Stable	Excellent	Significant
El Paso Electric Company	EE	BBB/Stable	Strong	Significant
Emera Inc.	EMA	BBB+/Negative	Excellent	Aggressive
Entergy Corporation	ETR	BBB/Positive	Strong	Significant
FirstEnergy Corporation	FE	BBB-/Stable	Strong	Significant
Fortis Inc.	FTS	A-/Stable	Excellent	Significant
Great Plains Energy Inc.	GXP	BBB+/Stable	Excellent	Significant
IDACORP, Inc.	IDA	BBB/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Strong	Intermediate
PG&E Corporation	PCG	BBB/Positive	Strong	Significant
Pinnacle West Capital Corporation	PNW	A-/Stable	Excellent	Intermediate
PNM Resources, Inc.	PNM	BBB+/Stable	Strong	Significant
Portland General Electric Company	POR	BBB/Stable	Strong	Significant
Southern Company	SO	A-/Negative	Excellent	Significant
Westar Energy, Inc.	WR	BBB+/Stable	Excellent	Significant
Xcel Energy Inc.	XEL	A-/Stable	Excellent	Significant

## RISK ANALYSIS

In order to evaluate the comparability of the proxy group companies, Concentric has examined the business risks of each operating company relative to those of OPG. The purpose of this evaluation was to determine the extent to which the companies in the proxy group have similar risk profiles to OPG (indicating that OPG is of average risk, compared to the proxy group), or are more or less risky than OPG (indicating a need to potentially establish a proxy-based capital structure for OPG that is above or below the mean and median of the group).

## A. Business Risk

As noted previously, business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. For purposes of this report, Concentric has focused on four primary business risks:

- i. Operational profile;
- ii. Generation percentage and mix;
- iii. Capital expenditures; and
- iv. Cost recovery risk.

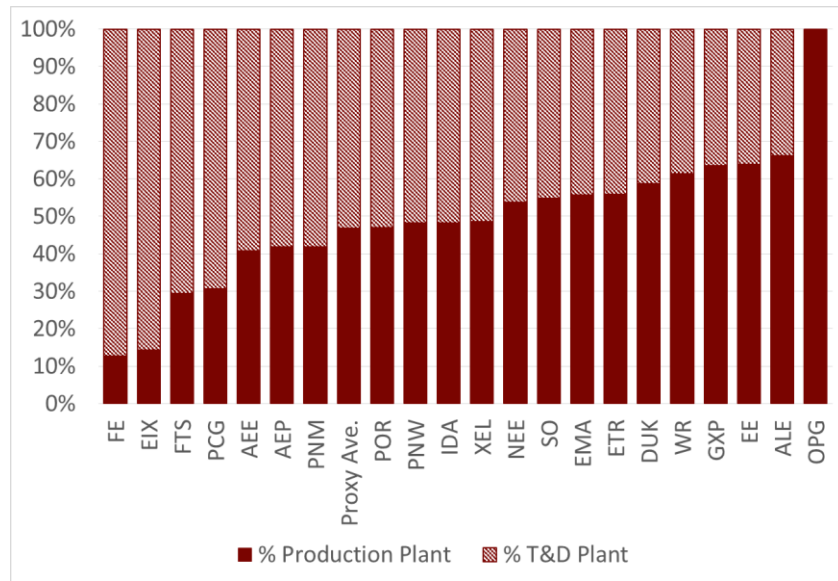
### i. Operational Profile

Concentric examined the operations and financing of each of the companies in the proxy group. Exhibit 2 provides a summary of several relevant indicators for the proxy group companies, including: (1) the province or state in which the utility provides service; (2) the S&P credit rating for the parent company; (3) the most recent deemed equity ratio for the operating company; and (4) regulated electricity revenues for the most recent year available. Exhibit 3 provides a summary of the various cost recovery mechanisms in place at the operating subsidiaries of the proxy group companies, including automatic adjustment clauses, cost trackers and variance accounts.

### ii. Generation Percentage and Mix

Concentric analyzed the generation percentage and mix of each proxy company to assess the percentage of each company's assets that is generation, and further, the percentage of generation capacity that is comprised of nuclear generation. As shown in Figure 6, OPG is the only company in the proxy group that is a pure-play regulated generation company. As discussed above, the investment community generally considers the generation function to be higher risk than other regulated electric operations.

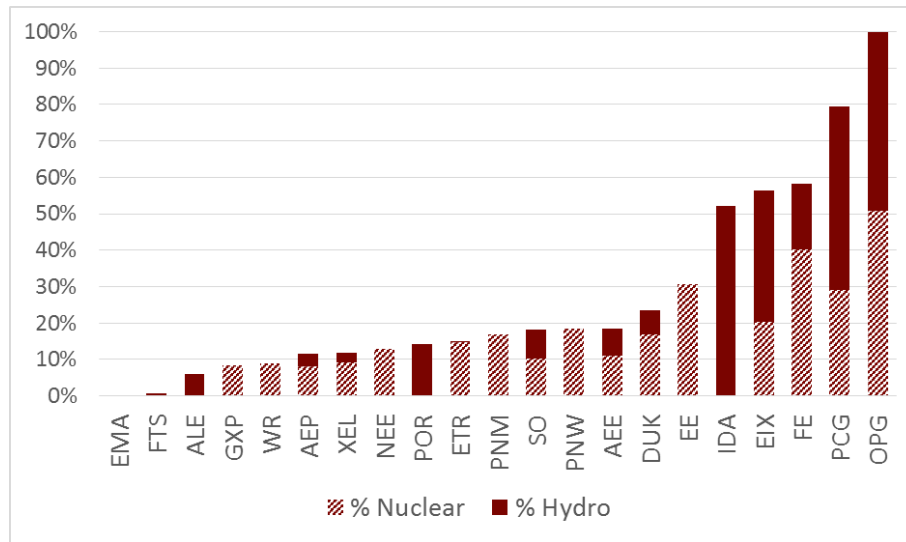
Figure 6: Generation versus Transmission and Distribution Assets



In addition, Figure 7 demonstrates that OPG has the greatest percentage of nuclear generation plant in relation to total generating assets of any company in the proxy group. Only one company (*i.e.*, FirstEnergy Corporation (“FE”)) comes close, but this is effectively offset, from a risk perspective, by ownership of transmission and distribution (“T&D”) assets (*see*, Figure 6). In EB-2013-0321, the Board stated, “the business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets.”<sup>62</sup> Based on this assessment that nuclear assets are more risky than hydroelectric assets (and the investment community’s view that generation, in general, is the riskiest business segment for a regulated utility), Concentric concludes that OPG is more risky than the proxy companies because of its nuclear generation concentration, as well as its overall concentration in generation in relation to lower risk T&D assets. In addition, while OPG has a high relative concentration of hydroelectric assets, other companies in the proxy group also have significant proportions of the generation mix in hydroelectric assets, with certain proxy companies such as IDACORP, Inc. (“IDA”), and to a lesser extent Portland General Electric Company (“POR”), and ALLETE, Inc. (“ALE”), being concentrated in that area.

<sup>62</sup> EB-2013-0321, Decision with Reasons, at 114.

Figure 7: Generation Mix (MW), Percentage Hydro and Nuclear Generation<sup>63</sup>

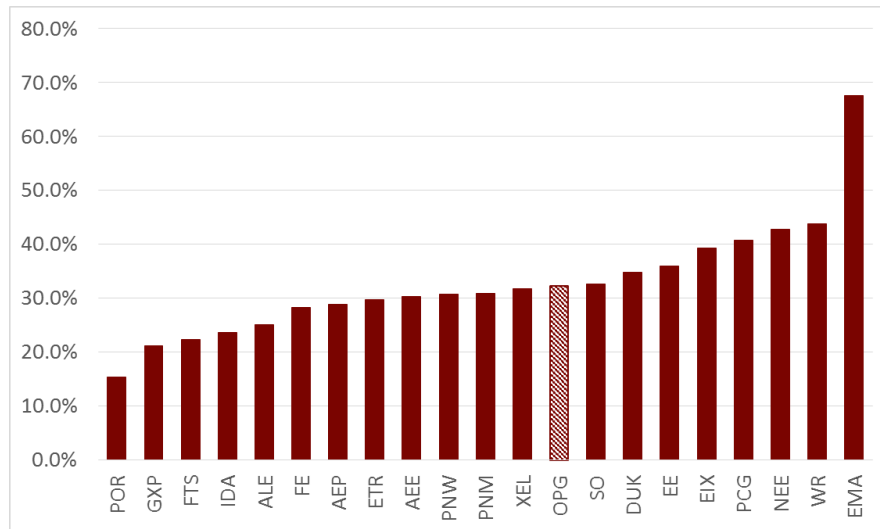


iii. Capital Expenditures

OPG is projecting a substantial investment in the future generation capacity of the province and will require continued access to capital on reasonable terms in order to finance this investment and maintain the Company’s current investment grade credit rating. Figure 8 displays forecast capital spending for the period from 2018-2020 as a percentage of net in-service utility PP&E as of December 31, 2014 (*i.e.*, the most recent consistently-available date for the proxy group) for each of the proxy companies and OPG. Before consideration of the entire scope of the DRP, OPG’s forecast capital expenditure ratio of 32.3% is above the median forecasted capital expenditure ratio of 30.9% for the proxy group companies. However, consideration of the full scope of the DRP (which, as discussed in Figure 2, is estimated at 62% of the Company’s net PP&E) would place OPG at the high end of the chart. Therefore, OPG has, at a minimum, somewhat more risk than these other companies on this factor. Once the DRP is accounted for, OPG’s forecast capital expenditure plan puts it at even greater than average risk compared to the proxy group.

<sup>63</sup> Based on regulated capacity owned.

Figure 8: Forecasted Capital Spending/ Net PP&E<sup>64</sup>



iv. Cost Recovery Risk

Exhibit 3 shows many of the deferral and variance accounts and riders used by each of the proxy companies as well as OPG. Some of OPG’s main deferral and variance accounts include accounts related to certain changes in nuclear decommissioning and nuclear waste management liability, capacity refurbishment costs, variability in water flows, foregone hydroelectric production due to surplus baseload conditions, and certain changes in income taxes. As can be seen in the exhibit, the proxy group companies likewise have many accounts with similar risk-mitigating properties, and therefore, Concentric concludes that in this respect OPG is generally risk comparable to the proxy companies, assuming these accounts are authorized to continue in the upcoming proceeding. Should some of these accounts not continue, OPG’s risk level may increase.

B. Financial Risk

In order to assess the financial risk of OPG relative to the proxy group, Concentric analyzed the allowed equity ratios for these companies. The proxy group average and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for OPG, after consideration of differences in risk profile between the Company and the proxy group. Specifically, the mean is “generally the best measure of central location for purposes of statistical inference,”<sup>65</sup> while also being at risk of being “unduly influenced by extreme observations.”<sup>66</sup> The median, or middle point of a set of observations at which half of the set of observations are above it and half are below it, is not subject to the same distortion due to extreme

<sup>64</sup> The U.S. capital expenditure and net plant data are calculated using Value Line data: capital spending per share and common shares outstanding. All U.S. forecasts are for the period 2018-2020. Canadian data were gathered from publicly available sources.

<sup>65</sup> Keller and Warrack, *Statistics for Management and Economics*, 5e ed., Duxbury Thompson Learning, 2000, at 92.

<sup>66</sup> *Ibid.*

observations.<sup>67</sup> Figure 9 summarizes the proxy group results in tabular format, and Figure 10 presents the results graphically.

Figure 9: Proxy Group Equity Ratios<sup>68</sup>

Company	Equity Ratio %
ALE	54.29
AEE	50.87
AEP	45.77
DUK	50.14
EIX	48.00
EE	NA
EMA	40.27
ETR <sup>69</sup>	46.27
FE	49.22
FTS	43.31
GXP	51.04
IDA	49.90
NEE	NA
PCG	52.00
PNW	53.94
PNM	45.00
POR	50.00
SO	49.09
WR	50.13
XEL	53.89
<b>Proxy Average</b>	49.06
<b>Proxy Median</b>	49.95
<b>OPG<sup>70</sup></b>	45.00

<sup>67</sup> *Ibid.*, at 93.

<sup>68</sup> Represents a composite equity ratio for each holding company based on a weighting of each holding company's jurisdictional utility equity ratios. Equity ratios were weighted by total retail electric customers for each jurisdictional utility. Companies with an "NA" for an equity ratio are those for which the most recent rate case parameters were not provided and/or public information was not available via SNL.

<sup>69</sup> Entergy Arkansas equity ratio adjusted to exclude zero cost capital items.

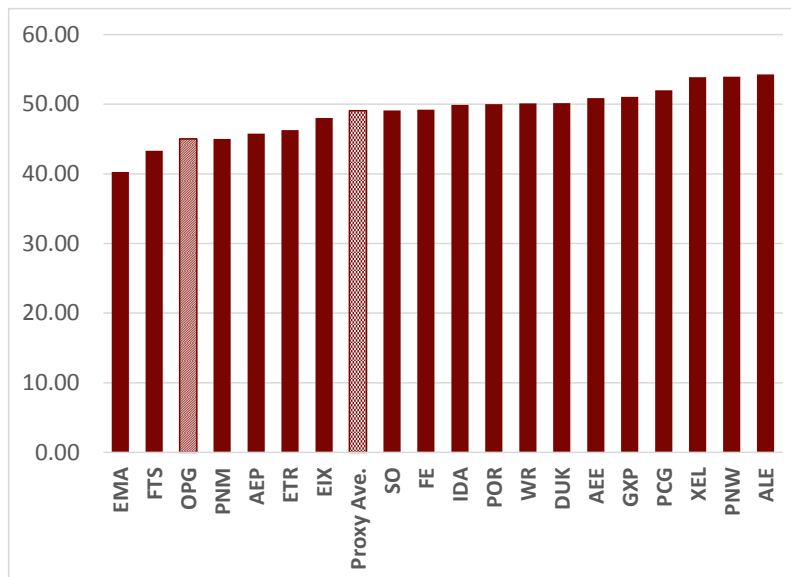
<sup>70</sup> Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

As shown in Figures 9 and 10, OPG’s deemed equity ratio is 45% as compared to the proxy average of 49.06% and median of 49.95%. OPG’s deemed equity ratio is 4.06 percentage points below the proxy group average, 4.95 percentage points below the proxy group median, and the third lowest overall.

The two Canadian companies, Emera and Fortis, as well as two U.S. companies, AEP and PNM, have equity ratios close to OPG’s, but these companies have substantial T&D assets to mitigate their generation risk. As discussed previously, generation assets are generally considered riskier from an investment perspective than T&D assets because generation assets typically have longer construction lead times, are subject to production risk and to risk from changes in environmental regulations and requirements, and are more subject to technological obsolescence. For example, in EB-2007-0905, the Board concluded: “OPG’s nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation.”<sup>71</sup> In that same decision, the Board also commented on the relative risk of generation as follows: “The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation.”<sup>72</sup>

Figure 6, presented earlier, provides the percentage of generation assets and T&D assets for OPG and the proxy group companies. As shown in that Figure, 100% of OPG’s assets are dedicated to generation, while the proxy group companies have a mixture of generation assets and T&D assets. As discussed above, the Board has recognized that generation assets are typically considered riskier than T&D assets. On that basis, OPG has higher business risk than the proxy group companies, which suggests a higher deemed equity ratio is appropriate for OPG.

Figure 10: Proxy Company Allowed Equity Ratios<sup>73</sup>



With the lower deemed equity ratio of OPG compared to the proxy group companies, Concentric

<sup>71</sup> EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.

<sup>72</sup> *Ibid.*

<sup>73</sup> Represents composite equity ratio for each holding company based on weighting of jurisdictional equity ratios. Equity ratios weighted by total retail electric customers. Excluded companies for which most recent rate case parameters were not provided and/or public information was not available via SNL.

concludes that OPG has greater financial risk than the proxy group. Concentric also considers that OPG would be rated two notches lower than its corporate rating on a stand alone basis according to S&P. This point is underscored by the S&P rating of OPG's financial risk as "Aggressive". Only one other proxy group company, Emera, is rated Aggressive on financial risk. All others are rated better at "Significant" or "Intermediate" on financial risk, and one half of the companies also have better business risk ratings at "Excellent" by S&P, as illustrated in Figure 5. As a result, the risk profile of OPG suggests OPG's equity ratio should fall at the upper end of the proxy group.

## COMPARATIVE ANALYSIS CONCLUSIONS

Based on the comparative analyses of business and financial risk, Concentric draws the following conclusions:

- OPG's generation mix is comprised of more nuclear generation than the proxy group, indicating that OPG is riskier than the group on this factor.
- OPG has an asset mix that is 100% generation in contrast to the proxy group companies with an average of 47%, making OPG a riskier business.
- OPG's capital expenditure forecasts are higher than average for the proxy group over the near-term, indicating that OPG is riskier than the group. In addition, when the full scope of the DRP is considered, OPG's ratio of capital expenditures to net PP&E will increase substantially, indicating even higher relative risk for the Company.
- OPG has several deferral and variance accounts for its operations, as do other proxy companies; therefore, the Company is considered to be risk comparable to the proxy group in this area.
- OPG's deemed equity ratio is lower than all but two other proxy companies, exposing OPG to more financial risk than the proxy companies.

On a relative risk basis, Concentric finds OPG, with its significant nuclear concentration, a pure generating company business profile, and the magnitude of its capital spending program, to fall towards the upper end of the spectrum of risk profiles established by the proxy companies, which have mean and median equity ratios between 49% and 50%. Therefore, Concentric believes the proxy group average equity ratio of approximately 49% provides a floor for the consideration of an appropriate equity ratio for the Company in the upcoming rate proceeding.

SECTION 6:

## CONCLUSIONS AND RECOMMENDATIONS

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The fair return standard requires that three standards for the cost of capital be met: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard. In addition, the Board has established that it will reassess a utility's capital structure when there have been significant changes in the company's business and/or financial risk. Concentric's analysis of changes to OPG's risk profile, as well as the relatively greater risk of OPG in relation to the proxy companies, indicates that OPG's current equity ratio of 45% no longer meets the fair return standard and is thus no longer adequate for the Company.

Concentric concludes that OPG's risk profile will change materially, and will specifically increase, over the 2017-2021 period as compared to its risk profile at the time of EB-2013-0321. Specifically, OPG's generation mix will change to reflect a significantly higher proportion of nuclear generation than when the Board set the common equity ratio at 45% in EB-2013-0321. By the end of the test period in 2021, nuclear rate base will exceed the relative level at which it stood when the Board set OPG's common equity ratio at 47% in EB-2007-0905 and EB-2010-0008. Given the Board's EB-2013-0321 finding that "[t]he business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets,"<sup>74</sup> the opposite must hold equally true: business risk will have increased because of the addition of significant nuclear assets to rate base, which are more risky than hydroelectric assets.

In addition, while the operating risks of the hydroelectric business are generally expected to remain at current levels, they are expected to increase for the nuclear business in the 2017–2021 payment amount period. Finally, the increased forecasting risk and uncertainty related to the Company's planned five-year ratemaking proposal further increases the Company's business and financial risks. That finding is consistent with DBRS' assessment of the change in risk scores for utilities moving from cost-of-service regulation to incentive regulation. Furthermore, OPG's nuclear rate smoothing proposal, in conjunction with the significant cash flow requirements of the DRP, will put pressure on the Company's credit metrics and increase its financial risk. Thus, Concentric's opinion is that an appropriate equity ratio for the Company exceeds the deemed ratio of 45% set by the Board in the EB-2013-0321 rate proceeding.

The range of common equity ratios for comparable utilities is 40.27% to 54.29%, with the average equity ratio being 49.06% and the median being 49.95%. OPG's current equity ratio of 45% is on the low end of the comparable group, having the third lowest equity ratio despite its elevated level of risk relative to the proxy group. Specifically, with its significant nuclear concentration, as well as its status as the only company in the group that is a pure generating company, and its significant capital expenditure program, OPG falls toward the upper end of the risk spectrum. Thus, given OPG's elevated risk relative to the average level of risk faced by the proxy group, Concentric believes the proxy group average equity ratio of approximately 49% provides a floor for the consideration of an appropriate equity ratio for the Company in the upcoming rate proceeding.

In summary, given the Company's projected increase in risks since EB-2013-0321, the change in the nuclear to hydroelectric asset mix, the increase in OPG's risk level driven by uncertainty

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<sup>74</sup> EB-2013-0321, Decision with Reasons, at 114.

surrounding the Darlington refurbishment project in particular, plans to pursue extended Pickering operations and the move to incentive regulation, as well as OPG's higher risk relative to comparable firms whose equity ratios average over 49%, Concentric recommends an equity ratio of no less than 49% be set in this proceeding.

APPENDIX A:

## PRECEDENT FOR CONSIDERING U.S. DATA

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There is precedent among Canadian regulators for considering U.S. data and a U.S. proxy group for cost of capital evaluations. In recent orders, other Canadian regulators have determined that it is appropriate to consider the use of U.S. data and U.S. proxy groups to estimate the allowed ROE for a Canadian regulated utility. Regulators in Canada have noted several reasons that support consideration of U.S. data. First, the development of a proxy group comprised entirely of Canadian electric utilities is difficult due to the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than the provision of regulated electric utility service. Second, this problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies. The question for Canadian regulators has become: How do we account for any differences in risk between U.S. and Canadian utilities? Concentric's research and analysis demonstrate that it is possible to select a group of U.S. electric utilities that is comparable to Canadian utilities in terms of business and operating risk. In that regard, Concentric agrees with the conclusion of the Board that it is not necessary to find that utilities are the same, only that they are comparable,<sup>75</sup> and with the NEB's conclusion that it is possible to account for differences in risk that would influence an investor's required rate of return.<sup>76</sup>

A growing number of Canadian utility regulators have accepted the use of U.S. data or U.S. proxy groups in recent years. For example, in its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. The NEB appears to view U.S. market returns as valuable information in establishing the cost of capital for Canadian utilities. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.<sup>77</sup> Importantly, the NEB also found that the regulatory regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries, stating:

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*The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to*

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<sup>75</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 21.

<sup>76</sup> National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 71.

<sup>77</sup> *Ibid.*, at 66-72.

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*weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.*<sup>78</sup>

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Likewise, the OEB concluded that the U.S. is a relevant source of comparable data and that it often looks to the U.S. to inform its decisions:

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*The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*

*Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.*<sup>79</sup>

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Finally, the British Columbia Utilities Commission ("BCUC") accepted the use of U.S. data, stating:

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*In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.*<sup>80</sup>

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The BCUC affirmed this position in its 2013 Generic Cost of Capital Decision:

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*The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, we have determined that it is appropriate to continue to accept*

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<sup>78</sup> *Ibid.*

<sup>79</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23.

<sup>80</sup> British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 16.

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*the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.*

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And,

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*[I]n the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.<sup>81</sup>*

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In summary, regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are often limited by the small number of publicly-traded utilities. They have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes. Therefore, they have determined that it is reasonable and appropriate to consider the results of a risk comparable U.S. proxy group for purposes of cost of capital analyses for a Canadian natural gas or electric utility. These findings suggest that it is reasonable and appropriate to consider a proxy group of U.S. utility companies as sufficiently comparable to Canadian regulated utilities in terms of their risk profile.

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<sup>81</sup> British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage I), Decision, May 10, 2013, at 20.

APPENDIX B:

## Résumé and Testimony Listing of James M. Coyne

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### **James M. Coyne** **Senior Vice President**

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Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

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### **REPRESENTATIVE PROJECT EXPERIENCE**

#### **Expert Testimony Experience**

- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, provided expert testimony on the cost of capital and business risk for the Company's gas distribution operations. (Docket No. \_\_)
- Northern States Power Co.: Before the Minnesota Public Utilities Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. E002/GR-15-826)
- Maritime Electric: Before the Island Regulatory and Appeals Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. UE20942)
- Newfoundland Power Inc.: Before the Newfoundland and Labrador Board of Commissioners of Public Utilities, provided expert testimony on the cost of capital and business risk for the Company's electric distribution operations. (2016/2017 General Rate Application)
- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No. 3698852)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on performance based regulation recommendations for the Company's Québec electric transmission and distribution businesses, with Robert Yardley. (R-3897-2014)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)

- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)
- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 - )
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution

business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)

- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)

- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

### **Regulatory Support Experience**

- Provided consulting services to Hydro One Networks for the Company's 2015 - 2019 Custom Distribution Rate Application to the OEB. Assisted the Company in developing its proposal for specific performance metrics for the Plan; reviewed the comments of stakeholders on performance metrics; reviewed the Company's existing performance metrics; reviewed the fastest growing areas of budgeted expenditures for their performance metric potential; developed a set of recommended metrics for review with the Company; and assisted the Company with drafting its submission to the OEB. (2014)
- Advised the Ontario Power Authority (OPA) on appropriate efficiency metrics to utilize in measuring the effectiveness of the organization in response to a directive by the Ontario Energy Board. Conducted research and analysis to examine efficiency metrics used in the industry to measure the effectiveness of organizations with similar responsibilities to those of the OPA. This analysis was designed to help facilitate the OPA's recommended metrics to the OEB. (2013)
- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs.

parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)

- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

#### **Areas of Expertise**

- **Energy Regulation**
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- **Management and Business Strategy**
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- **Financial and Economic Advisory**
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

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#### **PUBLICATIONS AND RESEARCH**

- “Stimulating Innovation on Behalf of Canada’s Electricity and Natural Gas Consumers” (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.
- “Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results” (with John Trogonoski), Public Utilities Fortnightly, May 2010
- “A Comparative Analysis of Return on Equity of Natural Gas Utilities” (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007
- “Do Utilities Mergers Deliver?” (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

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- “Winners and Losers: Utility Strategy and Shareholder Return” (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
  - “Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance” (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
  - “The New Generation Business,” commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
  - Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
  - “Natural Gas Outlook,” articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989
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### **SELECTED SPEAKING ENGAGEMENTS**

- “Innovations in Utility Business Models and Regulation”, The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
  - “M&A and Valuations,” Panelist at Infocast Utility Scale Solar Summit, September 2010
  - “The Use of Expert Evidence,” The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
  - “A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.,” The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
  - “Nuclear Power on the Verge of a New Era,” moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
  - “The Investment Implications of the Repeal of PUCHA,” Skadden Arps Client Conference, New York, NY, October 2005
  - “Anatomy of the Deal,” First Annual Energy Transactions Conference, Newport, RI, May 2005
  - “The Outlook for Wind Power,” Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
  - “Direction of U.S. M&A Activity for Utilities,” Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
  - “Outlook for U.S. Merger & Acquisition Activity,” Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
  - “Investor Perspectives on Emerging Energy Companies,” Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
  - “Electric Generation Asset Transactions: A Practical Guide,” workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
  - “New Strategic Options for the Power Sector,” Electric Utility Business Environment Conference, Denver, CO, May 1999
  - “Electric and Gas Industries: Moving Forward Together,” New England Gas Association Annual Meeting, November 1998
  - “Opportunities and Challenges in the Electric Marketplace,” Electric Power Research Institute, July 1998
-

## PROFESSIONAL HISTORY

### **Concentric Energy Advisors, Inc. (2006 – Present)**

Senior Vice President

Vice President

### **FTI Consulting (Lexecon) (2002 – 2006)**

Senior Managing Director – Energy Practice

### **Arthur Andersen LLP (2000 – 2002)**

Managing Director, Andersen Corporate Finance – Energy and Utilities

### **Navigant Consulting, Inc. (1996 – 2000)**

Managing Director, Financial Services Practice

Senior Vice President, Strategy Practice

### **TotalFinaElf (1990 – 1996)**

Manager, Corporate Planning and Development

Manager, Investor Relations

Manager of Strategic Planning and Vice President, Natural Gas Division

### **Arthur D. Little, Inc. (1989 – 1990)**

Senior Consultant – International Energy Practice

### **DRI/McGraw-Hill (1984 – 1989)**

Director, North American Natural Gas Consulting

Senior Economist, U.S. Electricity Service

### **Massachusetts Energy Facilities Siting Council (1982 – 1984)**

Senior Economist – Gas and Electric Utilities

### **Maine Office of Energy Resources (1981 – 1982)**

State Energy Economist

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## EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981

B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

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## DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

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President, International Association for Energy Economics, Dallas Chapter, 1995  
Gas Research Institute, Economics Advisory Committee, 1990-1993  
Georgetown University, Alumni Admissions Interviewer, 1988 – current

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
<b>Alberta Utilities Commission</b>				
ATCO Utilities Group	2008	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
<b>American Arbitration Association</b>				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
<b>British Columbia Utilities Commission</b>				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015	FortisBC Utilities	Project 3698852	Cost of Capital (Gas Distribution)
<b>Connecticut Department of Public Utility Control</b>				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
<b>Federal Energy Regulatory Commission</b>				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
<b>Maine Public Utility Commission</b>				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
<b>Massachusetts Superior Court</b>				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
<b>Minnesota Public Utilities Commission</b>				
Northern States Power Company	2015	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
<b>Newfoundland and Labrador Board of Commissioners of Public Utilities</b>				
Newfoundland Power	2015 2016	Newfoundland Power	2016/2017 GRA	Cost of Capital (Electric)
<b>New Jersey Board of Public Utilities</b>				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
<b>Nova Scotia Utility and Review Board</b>				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
<b>Ontario Energy Board</b>				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
<b>Prince Edward Island Regulatory and Appeals Commission</b>				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
<b>Régie de l'énergie du Québec</b>				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
<b>South Dakota Public Service Commission</b>				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
<b>Texas Public Utility Commission</b>				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
<b>Vermont Public Service Board</b>				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.		Return on Equity (Gas Distribution)
<b>Wisconsin Public Service Commission</b>				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)

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APPENDIX C:

## Résumé and Testimony Listing of Daniel S. Dane

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### **Daniel S. Dane, CPA** **Assistant Vice President**

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Daniel S. Dane has extensive experience in the energy and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, generating asset divestitures, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters for investor-owned utilities. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

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### **REPRESENTATIVE PROJECT EXPERIENCE**

#### **Ratemaking and Utility Regulation Assignments**

##### **Expert Testimony**

- Submitted expert direct testimony on behalf of Northern States Power, a wholly-owned subsidiary of Xcel Energy Inc., to present evidence and provide an opinion regarding the company's proposed ROE in South Dakota Public Utilities Commission Docket No. EL11-019.
- Submitted expert direct and rebuttal testimony on behalf of Ameren's Illinois utilities regarding ratemaking policy issues specifically related to regulated rate base (Illinois Commerce Commission Docket No. 09-0306 through 09-0311 (Cons.)).

##### **Regulatory Support**

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric and natural gas utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; and ratemaking policy.
- Developed marketing materials, regulatory filings, and cost of service/rate design financial models for natural gas pipeline facilities for U.S. and state regulatory filings and open seasons.
- For natural gas pipeline filings, advised applicants on Federal Energy Regulatory Commission (FERC) policies and precedent regarding tariff rates and other filing requirements.

- Developed market power studies, along with supporting testimony, for developers and owners of U.S. natural gas storage facilities.
- Assignments include utilities in Ontario, Alaska, Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, North Dakota, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, North Dakota, Texas, Wisconsin, Vermont, and the District of Columbia.

## **Financial Advisory Assignments**

### **Competitive Solicitations & Asset Divestitures**

- Sell-side support provide for approximately \$2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S. and international investors in wind generation and natural gas pipeline facilities.

### **Valuation Services**

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

## **Litigation Advisory Assignments**

Prepared economic and financial analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

## **Management and Operations Consulting Assignments**

Prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear generating capacity uprates and new nuclear facilities.

---

## **PRESENTATIONS**

“Increasing Shareholder Value through the Capital Markets.” University of Idaho Utility Executive Course, June 2015.

“A Comparative Analysis of Return on Equity of Natural Gas Utilities” (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

---

## **PROFESSIONAL HISTORY**

### **Concentric Energy Advisors, Inc. (2004 – Present)**

#### **CE Capital Advisors, Inc.**

Assistant Vice President (Concentric)

Financial and Operations Principal (CE Capital)

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**Ernst & Young (2000 - 2001, 2003 - 2004)**  
Staff Auditor and Database Management Associate

**ZIA Information Analysis Group (1997 - 2000)**

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**EDUCATION AND CERTIFICATIONS**

M.B.A., Boston College, 2003  
B.A., Economics, Colgate University, 1996  
Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

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**DESIGNATIONS AND PROFESSIONAL AFFILIATIONS**

Certified Public Accountant, 2004  
Massachusetts Society of Certified Public Accountants, 2004  
American Institute of Certified Public Accountants, 2011

### Exhibit 1: Proxy Group Criteria

	Company [1]	Ticker	Credit Rating (Criteria: Investment Grade)	Generation Assets Included in Rate Base	Regulated Revenue / Total Revenue (Criteria: >60%)	Regulated Income / Total Income (Criteria: >60%)	Regulated Electric Revenue / Total Reg. Revenue (Criteria: >80%)	Regulated Electric Income / Total Reg. Income (Criteria: >80%)	Fuel Mix: Percent Nuclear [2]	Fuel Mix: Percent Hydro [2]
1	ALLETE, Inc.	ALE	BBB+	Yes	90%	101%	97%	97%	0%	6%
2	Ameren Corporation	AEE	BBB+	Yes	100%	102%	83%	89%	11%	7%
3	American Electric Power Company, Inc.	AEP	BBB	Yes	92%	85%	100%	100%	8%	3%
4	Duke Energy Corporation	DUK	A-	Yes	92%	102%	98%	97%	17%	7%
5	Edison International	EIX	BBB+	Yes	100%	101%	100%	100%	20%	36%
6	El Paso Electric Company	EE	BBB	Yes	100%	100%	100%	100%	31%	0%
7	Emera Inc. [3]	EMA	BBB+	Yes	87%	86%	98%	86%	0%	0%
8	Entergy Corporation	ETR	BBB	Yes	79%	96%	98%	99%	15%	0%
9	FirstEnergy Corporation	FE	BBB-	Yes	64%	113%	100%	100%	40%	18%
10	Fortis Inc. [3]	FTS	A-	Yes	94%	94%	63%	62%	0%	1%
11	Great Plains Energy Inc.	GXP	BBB+	Yes	100%	101%	100%	100%	8%	0%
12	IDACORP, Inc.	IDA	BBB	Yes	100%	100%	100%	100%	0%	52%
13	NextEra Energy, Inc.	NEE	A-	Yes	69%	72%	100%	100%	13%	0%
14	PG&E Corporation	PCG	BBB	Yes	100%	100%	80%	96%	29%	50%
15	Pinnacle West Capital Corporation	PNW	A-	Yes	100%	100%	100%	100%	18%	0%
16	PNM Resources, Inc.	PNM	BBB+	Yes	100%	99%	100%	100%	17%	0%
17	Portland General Electric Company	POR	BBB	Yes	100%	100%	100%	100%	0%	14%
18	Southern Company	SO	A-	Yes	95%	93%	100%	100%	10%	8%



Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
ALE	ALLETE (Minnesota Power)	MN	54.29		
ALE [1]			54.29	BBB+	\$1,013,221
AEE	Union Electric Company	MO	51.76		
AEE	Ameren Illinois Company	IL	50.00		
AEE [1]			50.87	BBB+	\$4,953,315
AEP	Columbus Southern Power Company	OH	50.64		
AEP	Ohio Power Company	OH	53.79		
AEP	Appalachian Power Company	WV	47.16		
AEP	Indiana Michigan Power Company	IN	42.67		
AEP	Appalachian Power Company	VA	42.89		
AEP	Indiana Michigan Power Company	MI	42.07		
AEP	Southwestern Electric Power Company	AR	33.99		
AEP	AEP Texas Central Company	TX	40.00		
AEP	AEP Texas North Company	TX	40.00		
AEP	Southwestern Electric Power Company	TX	49.10		
AEP [1]			45.77	BBB	\$14,490,000
DUK	Duke Energy Ohio, Inc.	OH	53.30		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
DUK	Duke Energy Indiana, LLC	IN	44.44		
DUK	Duke Energy Florida, LLC	FL	45.74		
DUK	Duke Energy Carolinas, LLC	SC	53.00		
DUK	Duke Energy Progress, LLC	SC	44.72		
DUK	Duke Energy Progress, LLC	NC	53.00		
DUK	Duke Energy Carolinas, LLC	NC	53.00		
DUK [1]			50.14	A-	\$22,581,161
EIX	Southern California Edison Company	CA	48.00		
EIX [1]			48.00	BBB+	\$14,195,273
EE [2]	El Paso Electric Company		NA	BBB	\$917,525
EMA	Maine Public Service Company	ME	50.00		
EMA	Emera Maine	ME	49.00		
EMA	Nova Scotia Power Inc.	Nova Scotia	37.50		
EMA [1]			40.27	BBB+	\$2,067,200
ETR	Entergy Arkansas, Inc. [3]	AR	46.27		
ETR [1]			46.27	BBB	\$10,904,103
FE	Cleveland Electric Illuminating Company	OH	49.00		
FE	Ohio Edison Company	OH	49.00		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
FE	Toledo Edison Company	OH	49.00		
FE	Potomac Edison Company	WV	46.42		
FE	Jersey Central Power & Light Company	NJ	50.00		
FE [1]			49.22	BBB-	\$9,871,000
FTS	Central Hudson Gas & Electric Corporation	NY	48.00		
FTS	Tucson Electric Power Company	AZ	43.50		
FTS	UNS Electric, Inc.	AZ	52.60		
FTS	Fortis BC Electric	British Columbia	40.00		
FTS	Fortis Alberta	Alberta	40.00		
FTS	Newfoundland Power	Newfoundland & Labrador	45.00		
FTS	Maritime Electric	Prince Edward Island	40.00		
FTS	Fortis Ontario	Ontario	40.00		
FTS [1]			43.31	A-	\$3,554,612
GXP	KCP&L Greater Missouri Operations Company	MO	52.30		
GXP	Kansas City Power & Light Company	MO	50.09		
GXP	Kansas City Power & Light Company	KS	50.48		
GXP Weighted Average [1]			51.04	BBB+	\$2,568,200
IDA	Idaho Power Co.	OR	49.90		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
IDA [1]			49.90	BBB	\$1,278,651
NEE [2]	NextEra Energy Inc.		NA	A-	\$11,421,000
PCG	Pacific Gas and Electric Company	CA	52.00		
PCG [1]			52.00	BBB	\$13,658,000
PNW	Arizona Public Service Company	AZ	53.94		
PNW [1]			53.94	A-	\$3,491,632
PNM	Texas-New Mexico Power Company	TX	45.00		
PNM [1]			45.00	BBB+	\$1,435,853
POR	Portland General Electric Company	OR	50.00		
POR [1]			50.00	BBB	\$1,900,000
SO	Mississippi Power Company	MS	53.68		
SO	Alabama Power Company	AL	45.60		
SO	Georgia Power Company	GA	50.84		
SO [1]			49.09	A-	\$17,354,000
WR	Kansas Gas and Electric Company	KS	50.13		
WR [1]			50.13	BBB+	\$2,601,703
XEL	Northern States Power Company - MN	ND	52.56		
XEL	Public Service Company of Colorado	CO	56.00		



Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
<b>OPG</b>	Nuclear liability Nuclear development Capacity refurbishment Ancillary services net revenue – hydro & nuclear Hydroelectric water conditions Income and other taxes Nuclear and hydro deferral and variance over/under recovery Bruce lease net revenues Pension and OPEB cost Pension & OPEB cash payment and Pension & OPEB cash versus accrual differential Niagara Tunnel Project pre-December 2008 Disallowance Gross revenue charge Hydro incentive mechanism Hydro surplus base load generation Impact resulting from changes in station end-of-life dates
<b>AEE</b>	Purchased Power Cost Adjustment – Fuel Adjustment Clause (incl. Off-System Sales) Conservation Program Expense – DSM Program Recovery Partial Decoupling Renewables Expense – Renewable Energy Standards rate adjustment Environmental Compliance – Hazardous Materials Adjustment Clause Rider RTO-Related Transmission Expense Other – Bad Debt Cost Recovery Other – Certain Taxes and Franchise Fee Recovery
<b>ALE</b>	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance RTO-Related Transmission Expense
<b>AEP</b>	Purchased Power Cost Adjustment Conservation Program Expense – Energy Efficiency Rider Partial Decoupling Renewables Expense Environmental Compliance – Environmental Adjustment Clause Environmental Compliance – Energy Efficiency Rider Generation Capacity Generation Capacity – Big Sandy Plant Recovery Generic Infrastructure – T&D and storage system improvement charge rider Generic Infrastructure – CWIP Recovery Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Electric Security Plans RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Sharing Mechanism Other – Compliance and Cyber-security Requirements

<b>Company</b>	<b>Inter-Rate Case Cost Recovery and other Adjustment Mechanisms</b>
<b>DUK</b>	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Recovery Rider Partial Decoupling Renewables Expense Renewables Expense – EPS Rider Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Margin Sharing Mechanism
<b>EE</b>	Purchased Power Cost Adjustment Conservation Program Expense Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
<b>EIX</b>	Purchased Power Cost Adjustment Full Decoupling
<b>ETR</b>	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Programs Partial Decoupling Environmental Compliance – Environmental Adjustment Clause Generation Capacity – Capacity Acquisition Rider Generation Capacity – New generation and Capacity Additions Generic Infrastructure – Distribution Cost Recovery Generic Infrastructure – Government-related Expenses RTO-Related Transmission Expense Other – Storm Cost Securitization
<b>FE</b>	Purchased Power Cost Adjustment – Electric Fuel Rate Conservation Program Expense Partial Decoupling Renewables Expense Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
<b>GXP</b>	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – Energy Cost Adjustment Mechanism
<b>IDA</b>	Purchased Power Cost Adjustment Renewables Expense Conservation Program Expense Partial Decoupling

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
<b>NEE</b>	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Transmission Cost of Service Mechanism Other – Certain Taxes and Franchise Fee Recovery
<b>PCG</b>	Purchased Power Cost Adjustment Full Decoupling
<b>PNM</b>	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
<b>PNW</b>	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Generation Capacity RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
<b>POR</b>	Purchased Power Cost Adjustment Partial Decoupling Renewables Expense
<b>SO</b>	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity Other – Certain Taxes and Franchise Fee Recovery Other – Storm Cost Securitization
<b>WR</b>	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling – Energy Efficiency Program Recovery Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
<b>XEL</b>	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Demand-Side Management Rider Conservation Program Expense – Energy Efficiency Rider Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Transmission Cost Recovery Rider Generic Infrastructure – Infrastructure Rider RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Sharing Mechanism Other – Limited Issue Reopener Other – Lost Revenue Rider Associated with University Discounts Other – "Non-asset-based" Wholesale Power Margin Sharing Other – Renewable Energy Credit Sales



Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
EMA	Deferred income tax regulatory asset Unamortized defeasance costs Fuel adjustment mechanism Deferrals related to derivative instruments Large industrial customers fixed cost deferral Stranded cost recovery Pension and post-retirement medical plan Stranded cost revenue & purchase power reconciliation deferrals Purchase power contracts Hydro-Québec Obligation November 2014 Maine storm 2013 Maine ice storm Earnings Share Mechanism Asset impairment recovery Seabrook nuclear project Deferral of income and capital taxes not included in Q1 2005 rates Smart Grid Rate stabilization fixed cost deferral Self-Insurance Fund Deferrals related to derivative instruments Deferred income tax regulatory liabilities Maine FERC ROE

*Sources:*

*U.S. Companies: SNL RRA Adjustment Mechanism Report as of October 2, 2015.*

*EMA & FTS: 2014 Consolidated Financial Statements and 2014 Annual Report and above SNL report, respectively*

*OPG: EB-2014-0370 and Company Data.*

# ONTARIO POWER GENERATION COMMON EQUITY RATIO STUDY

DECEMBER 31, 2020



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## SECTION 1: EXECUTIVE SUMMARY

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Concentric Energy Advisors, Inc. (“Concentric”) was retained to prepare this independent report as to whether the application of the cost of capital approved by the Ontario Energy Board (“OEB” or “Board”) in EB-2016-0152 is an appropriate basis for setting Ontario Power Generation’s (“OPG’s”) payment amounts in its next rate application. As the OEB has traditionally accounted for differences in risk through the deemed equity ratio for each regulated utility under its jurisdiction, rather than the authorized return on equity (“ROE”), Concentric’s analysis specifically focuses on OPG’s capital structure. OPG’s next rate application will cover the five-year period from 2022 to 2026.

In our analysis, OPG’s risk profile will increase materially during the 2022 to 2026 period, as compared to its risk profile at the time of EB-2016-0152. The most significant risk factors contributing to the increase are: the Darlington Refurbishment Project (“DRP”) entering a critical stage of execution; the continued operation of aging nuclear units; the retirement of the Pickering nuclear station; the continued shift of OPG’s rate base to reflect a greater portion of nuclear assets, combined with an increase in the financial value of each unit of nuclear output; and increasing climate change impacts. Given the increased risk profile, and OPG’s higher risk relative to other utilities that have equity ratios at the regulated operating company level that average from 49.5% to 55.9%, Concentric recommends that an equity ratio of no less than 50% be set for OPG in the upcoming proceeding.

Concentric followed the OEB’s preferred approach to assessing capital structure for the utilities it regulates by performing a detailed risk analysis of OPG, along with the changes to OPG’s risk profile and an assessment of the impact of current market conditions on the cost of capital. Concentric also examined OPG’s relative risk and equity ratio compared to other utilities. In addition, Concentric considered OPG’s current capital structure for consistency with the three components of the fair return standard: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard. Concentric’s analysis also included a review and consideration of the Board’s prior findings with regard to OPG’s equity thickness. In consideration of those findings, Concentric’s report provides further context and analysis regarding the drivers of risk for OPG and the comparability of U.S. and Canadian regulatory regimes.

Our recommended equity ratio for OPG in the upcoming rate setting period is set at a level that balances the results of our analysis, which indicates heightened risk for OPG on an absolute basis and



in comparison to peer companies and supports an equity ratio at the high end of the range of reasonable results (*i.e.*, 55% to 56%), with the OEB's prior findings. In our view, the recommended 50% is the minimum appropriate equity ratio for OPG. This is particularly important as the allowed return on equity ("ROE") by the OEB, currently 8.34%, is below the allowed ROEs for the proxy group companies.

### **Canadian Versus U.S. Historical Equity Ratios**

The OEB found in EB-2016-1052 that an adjustment was appropriate for U.S.-derived equity ratios due to the historical difference between authorized equity levels for Canadian and U.S. utilities. As discussed herein, Concentric's conclusion in this report is that an adjustment for differences in the allowed equity ratios between Canada and the U.S. is not necessary at this time (and on a forward-looking basis) because the business risk, including regulatory risk, for regulated utilities in the two countries is comparable, and the investment community's view is that any regulatory risk differential between the countries has narrowed significantly, if not disappeared. This view is supported by our interviews with equity and credit analysts covering the North American utility industry who indicated that any differences in business risk, including regulatory risk, between utilities in Canada and the U.S. are not sufficient to justify the historically wide gap in equity ratios between the two countries.

Based on this analysis, it is Concentric's view that an adjustment based on the existence of a historical difference between Canadian and U.S. deemed equity ratios would be inconsistent with the market's current views on cross-border business risk comparability, including regulatory risk, and would be inappropriate for purposes of setting OPG's regulatory capital structure on a forward-looking basis.

### **Business and Financial Risk Analysis**

Concentric's risk analysis focuses on: (a) the impact of current economic conditions on the cost of capital; (b) changes to OPG's business and financial risks since EB-2016-0152; (c) expected changes to OPG's risk profile and financial integrity on a forward-looking basis, consistent with how an investor would analyze OPG; and (d) for comparative purposes, a review of capital structure data for similar North American electric utilities. Because OPG's regulated capital structure is reflective of its overall risk profile related to the regulated operations, Concentric's analysis considered both the nuclear and hydroelectric businesses and their attendant risks.



### Economic Environment

In terms of the current economic environment and its impact on the cost of capital, several factors are at work. On the equity side, and notwithstanding the low government bond yields discussed below, sustained volatility in publicly traded equity markets in both Canada and the U.S. has made investors more risk-averse and safety conscious. In prior periods of market disruption, utilities have served as a safe haven for investors, but the ongoing COVID-19 pandemic, along with slumping demand and disruption to business plans, has left investors uncertain of the outlook for utilities. Utility betas, which measure the movement of individual stock prices in relation to the overall market, are well above their historical norms, and market indicators signal that the cost of equity for utilities has increased during the pandemic.

Applied to the OEB's framework for determining the cost of capital, the decline in the government bond yields is reflected in a decrease in allowed ROE from 8.52% for the 2020 year to 8.34% for the 2021 year, per the OEB's most recent update to the cost of capital parameters. This will place the allowed ROE in Ontario below that of any other North American regulatory jurisdiction, at a time when market views of utility risk appear to be increasing. For OPG specifically, the reduction in the allowed ROE will negatively affect OPG's credit metrics at a time when they are already expected to be pressured.

### Business and Financial Risks

With regard to business and financial risks, Concentric reaches the following summary conclusions.

- OPG continues to be at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators. This risk pervades and compounds OPG's other nuclear risks, discussed below.
- OPG is in the process of refurbishing the four-unit Darlington nuclear station as part of a \$12.8 billion "megaproject". OPG is subject to increased risk related to the DRP, compared to EB-2016-0152, due to new project execution risks in the upcoming rate-setting period, including the execution of new first-of-a-kind ("FOAK") scope, managing overlapping unit refurbishments, trades availability and constraints due to the COVID-19 pandemic.
- While the OEB found in EB-2016-0152 that the protections provided by Ontario Regulation 53/05 ("O. Reg. 53/05") mitigate OPG's risk related to the DRP, Concentric observes that the same is true for other North American nuclear generation owners that are undergoing large nuclear construction projects and have higher equity ratios than OPG. This report provides a

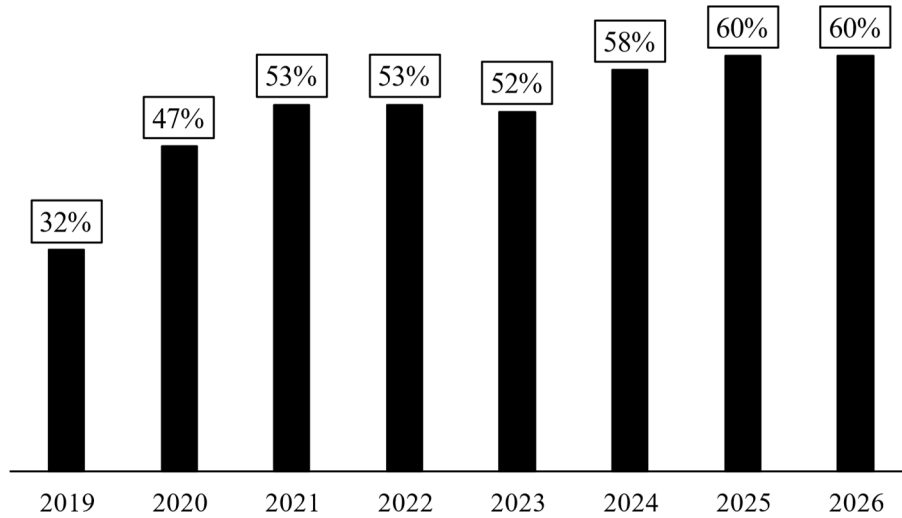


summary of legislative and regulatory mechanisms available in other jurisdictions, and how those mechanisms have protected (or failed to protect) the utility nuclear owners. As such, Concentric's recommended minimum equity ratio for OPG takes into account the risk reducing provisions for the DRP under O. Reg. 53/05. The recommendation also considers the impact of OPG's other material deferral and variance accounts related to the nuclear business.

- The majority of OPG's nuclear fleet is nearing the end of its current operating life, with the Pickering station set to end commercial operation during the upcoming rate period and Darlington units requiring refurbishment as they reach end of 'first' life during the period. Therefore, OPG faces an inherently increasing risk related to variability in generation output due to the aging of its nuclear stations, which can lead to significant revenue shortfalls.
- In addition to the increased generation risk leading up to the end of the station's commercial operations, the shutdown and retirement of Pickering, comprising 60% of the company's operating nuclear reactors and served by thousands of employees, in the upcoming rate period presents new and unique challenges for OPG related to significant disruptive organizational changes that can impact operational performance, increase forecast risk and reduce the diversification of OPG's nuclear fleet.
- OPG's regulated asset mix will continue to shift towards a higher proportion of nuclear assets, which, as the OEB previously found, are riskier than the hydroelectric business. Upon completion of the DRP in 2026, nuclear generation operations are projected to comprise approximately 60% of OPG's overall regulated rate base, compared to 32% as of December 31, 2019.



**Figure 1: Nuclear Portion of OPG’s Rate Base Over Time<sup>1</sup>**



The OEB found in EB-2016-0152 that, because *output* from OPG’s nuclear fleet was not increasing, the risk of OPG had not necessarily increased as a result of the changing rate base mix.<sup>2</sup> This report discusses that the *investment in plant*, which is ultimately recovered over output through the payment amounts, is the critical determinant of risk, notwithstanding changes in the relative output. In OPG’s case, the significant increase in relative investment in the nuclear fleet to be recovered drives the additional risk, even though the ratio of nuclear to hydroelectric generation output is not expected to increase.

This report also discusses that the *decline* in nuclear generation output due to the DRP and ultimately from the retirement of the Pickering station over the upcoming rate period creates *additional risk*. This is because each MWh of nuclear generation will become more financially valuable to OPG as the nuclear generation output that recovers the nuclear revenue requirement is reduced, while continuing to be more financially valuable than each MWh of hydroelectric generation.

For the above reasons, Concentric concludes that the increase in OPG’s nuclear rate base (both in absolute terms and relative to the total) combined with the decline in nuclear

<sup>1</sup> Excluding the provision for lesser of nuclear asset retirement costs and unfunded nuclear liability, which is consistent with the OEB-approved methodology for calculating OPG’s rate base subject to the weighted average cost of capital for purposes of setting payment amounts. Nuclear rate values are subject to filing of OPG’s final rate application with the OEB. Hydroelectric rate base is estimated based on OPG’s Amended 2020-2026 Business Plan.

<sup>2</sup> EB-2016-0152 Decision and Order, at 101-102.



generation will increase OPG’s risk profile over the next five years over-and-above its level of business risk in the prior payments amounts application.

- Risks to both OPG’s prescribed nuclear and hydroelectric operations from climate change have increased from the prior rate proceeding, including the risk of increased capital expenditure needs due to the threat of climate driven impacts on the company’s infrastructure and systems. The maintenance of hydroelectric base payment amount at the 2021 levels pursuant to a recent amendment to O. Reg. 53/05 will also increase inflationary risk for OPG.
- Concentric believes OPG’s financial risk will increase in the period from 2022 to 2026, as illustrated by the pressure on, and potential decline below current credit rating thresholds of, key credit metrics in the earlier years of the period. The credit metrics will be impacted by rate smoothing outcomes in the upcoming rate application.

Concentric concludes that, taken as a whole, this shift in risk profile since the time of EB-2016-0152 is sufficient to warrant a reassessment of OPG’s equity ratio.

### Equity Ratio Analysis and Recommendation

In terms of the comparable return requirement of the fair return standard, Figure 2 and Figure 3 below provide the average and median range of common equity ratios for two proxy groups of comparable utilities, including actual book equity ratios and regulated authorized equity ratios.

**Figure 2: Summary of Comparative Analysis Results (Concentric Proxy Group)**

<b>Analytical Approach</b>	<b>Mean Equity Ratio</b>	<b>Median Equity Ratio</b>
Holding Company Equity Ratios: 5-Year Avg.	45.7%	47.4%
Operating Company Equity Ratios: 5-Year Avg.	52.8%	53.0%
Operating Company Equity Ratios: Authorized	49.5%	49.6%

**Figure 3: Summary of Comparative Analysis Results (Moody’s Peer Group)**

<b>Analytical Approach</b>	<b>Mean Equity Ratio</b>	<b>Median Equity Ratio</b>
Holding Company Equity Ratios: 5-Year Avg.	50.6%	49.1%
Operating Company Equity Ratios: 5-Year Avg.	55.9%	53.6%
Operating Company Equity Ratios: Authorized	50.7%	50.1%

As shown in the Figure 2 and Figure 3, the average range of equity ratios is from 45.7% to 55.9%. This range includes equity ratios at both the holding company level (i.e., reflecting a diverse mix of



regulated entities and some non-regulated risk) and the exclusively regulated operating company level, which is the appropriate point of comparison for OPG's regulated operations. Focusing only on equity ratios at the regulated operating company level provides a narrower range of 49.5% to 55.9%, and even a narrower range of regulatory authorized equity ratios from 49.5% to 50.7%.

OPG's current equity ratio of 45% is below those ranges despite OPG's elevated level of risk relative to the proxy groups. The relative elevated risk reflects OPG's significant nuclear concentration, as well as its status as the only pure generation utility in the group, particularly when combined with its financial risks relative to the proxy groups and the revenue risk it faces related to nuclear output variability. On this latter point, OPG's being entirely at risk related to variability in the output of its nuclear facilities distinguishes it from other utilities, as the companies in the proxy group do not face comparable risk. On this basis, we believe OPG falls toward the upper end of the risk spectrum, reasonably supporting an equity ratio of 55% to 56% (*i.e.*, at the upper end of the proxy group results).

For this upcoming rate setting period, however, Concentric conservatively recommends an equity ratio of no less than 50% for OPG. This recommendation balances considerations related to OPG's heightened risk profile and proxy group position with the Board's findings in EB-2016-0152, as discussed herein.

### **Witness Duty**

We acknowledge that it is our duty to provide evidence in relation to this proceeding as follows:

- a. to provide opinion evidence that is fair, objective and non-partisan;
- b. to provide opinion evidence that is related only to matters that are within my area of expertise; and
- c. to provide such additional assistance as the OEB may reasonably require, to determine a matter in issue.

We acknowledge that the duty referred to above prevails over any obligation which we may owe to any party by whom or on whose behalf we are engaged.



## SECTION 2: SCOPE OF ANALYSIS AND OVERVIEW OF CONCENTRIC

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### Scope

Concentric was retained to prepare this independent report as to whether the application of the cost of capital approved by the OEB in EB-2016-0152 is an appropriate basis for setting payment amounts in OPG's next rate application. Concentric's analysis specifically focused on OPG's capital structure. In preparing this report, Concentric performed the following assessment:

1. Examined the OEB's decisions in EB-2007-0905, EB-2010-0008, EB-2013-0321 and EB-2016-0152 to understand the OEB's analysis and findings in past cases regarding OPG's cost of capital;
2. Analyzed OPG's business and financial risks since EB-2016-0152 and on a forward-looking basis consistent with how an investor would analyze OPG's risk profile;
3. Examined the capital structures of a proxy group of comparable companies; and
4. Determined an appropriate capital structure for OPG.

### Overview of Concentric

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised energy industry participants on the purchase and sale of nuclear facilities, hydroelectric facilities, and other generation assets, and we have served in an independent monitoring or project advisory function on major capital projects at several nuclear generating units in North America. Concentric also has experience relating to major refurbishment work on nuclear power life cycle management and extended power uprates in the U.S. and Canada. Concentric has provided expert testimony on the cost of capital in more than 100 regulatory proceedings in Canada and the U.S. over the past five years.

James Coyne, Senior Vice President at Concentric, and Daniel Dane, also a Senior Vice President at Concentric, coauthored this report with assistance from other Concentric staff. Mr. Coyne is a senior



expert who provides testimony before Canadian provincial and U.S. federal and state agencies on matters pertaining to economics, finance, and public policy in the energy industry. He regularly advises utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes determining the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. He has advised both buyers and sellers in numerous transactions involving hydroelectric, nuclear, fossil and renewable generation facilities, and worked with companies to develop strategies for acquiring these assets. He has testified or provided expert evidence before state, provincial and federal jurisdictions across Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions and staff.

Mr. Coyne is also a frequent speaker and author of articles and white papers on the energy industry. Recently, on behalf of the Canadian Gas Association and the Canadian Electric Association, he prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, he facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. In collaboration with the Canadian Gas and Canadian Electric Associations, he publishes a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. He has been an invited speaker for several CAMPUT events including the recent Energy Regulation Course at Queen's University where he spoke on "Innovations in Utility Business Models and Regulation." Mr. Coyne also coauthored a report titled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Dane that was prepared for the OEB in June 2007.

He holds a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire.

Mr. Dane has advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of those assignments have included the determination of the cost of capital. Mr. Dane has also provided expert testimony on regulated ratemaking matters, including the cost of capital, for investor-owned utilities and regulatory agencies. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the OEB, as discussed above. Mr. Dane has provided sell-



side support for approximately \$2 billion in generating asset transactions in the U.S., including nuclear generating facilities, and has been a significant contributor to numerous assignments at Concentric involving independent evaluations of nuclear plant construction project commercial strategies, project controls and management oversight, and new power plant development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

Messrs. Coyne and Dane's qualifications are detailed more fully in Appendices C and D.



### SECTION 3:

## BACKGROUND ON PRIOR OEB DECISIONS

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This is the fifth general rate setting proceeding before the Board for OPG. Below is a brief synopsis of the prior four 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 OEB, including cost of capital and capital structure. In its November 3, 2008 decision in EB-2007-0905, the OEB 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 OEB 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.”<sup>3</sup> The OEB further concluded that it would apply the stand-alone principle in establishing the capital structure for OPG, noting that “[t]he stand-alone principle is a long-established regulatory principle,”<sup>4</sup> and that “Provincial ownership will not be a factor to be considered by the Board in establishing capital structure.”<sup>5</sup> The OEB determined that a 47% equity ratio was appropriate for OPG, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.<sup>6</sup>

During EB-2007-0905, the OEB 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).<sup>7</sup>

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<sup>3</sup> EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.

<sup>4</sup> *Ibid.*, at 140.

<sup>5</sup> *Ibid.*, at 142.

<sup>6</sup> *Ibid.*, at 149-150.

<sup>7</sup> References to the “Pickering station” throughout the report encompass the Pickering A and Pickering B stations as prescribed under O. Reg. 53/05.



## EB-2009-0084

In EB-2009-0084, the OEB 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 OEB 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.<sup>8</sup> The OEB observed that meeting the fair return standard is not optional; it is a legal requirement.

In discussing the application of the fair return standard, the OEB made the following observations:<sup>9</sup>

1. The OEB notes that the fair return standard expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective;
2. The OEB agrees with the National Energy Board which stated that “[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced;”
3. All three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met, and none ranks in priority to the others;
4. The OEB reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for;
5. The OEB is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the fair return standard; and
6. The OEB questions whether the fair return standard has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the OEB is of the view that the capital attraction standard, indeed the fair return standard in totality, will be met if the cost of capital determined by the OEB is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital.

With respect to capital structure, the OEB found that its current policy for all regulated utilities, which was developed in March 1997, continued to be appropriate. The decision in EB-2009-0084 states:

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<sup>8</sup> EB-2009-0084, Report of the Board, December 11, 2009, at i.

<sup>9</sup> *Ibid.*, at 19-20.



“As noted in the Board’s draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.”<sup>10</sup>

The OEB also reiterated other policies, including that “the rate setting methodologies used by the OEB apply uniformly to all rate-regulated utilities regardless of ownership. The determination of the rate-regulated utilities’ cost of capital is no exception.”<sup>11</sup>

In 2016, the OEB issued an OEB Staff Report regarding the OEB’s cost of capital policy. In that report, OEB Staff concluded that no changes were to be made to the policy at that time.<sup>12</sup>

### EB-2010-0008

OPG’s generation asset mix as of EB-2010-0008 was at approximately 38% nuclear and 62% hydroelectric, based on OEB-approved rate base for the prescribed facilities (excluding the lesser of nuclear asset retirement costs and unfunded nuclear liability), which was approximately the same as it had been as of EB-2007-0905. In its March 11, 2011 decision in EB-2010-0008, the OEB found that “there is no evidence of any material change in OPG’s business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.”<sup>13</sup>

In EB-2010-0008, there was a discussion of technology-specific costs of capital and capital structures. Pollution Probe’s experts Drs. Lawrence Kryzanowski and Gordon Roberts recommended an equity ratio of 43% for the hydroelectric operations and an equity ratio of 53% for the nuclear operations, premised on OPG retaining its aggregate equity ratio of 47%. The OEB found that there was not enough evidence to support technology-specific capital structures and reaffirmed its findings in EB-2007-0905 that the risks related to nuclear generation are higher than those related to hydroelectric generation.

In addition, while the issue was identified by the OEB in the context of technology-specific capital structures, the OEB recognized an emerging issue, noting that “[a]s the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged.”<sup>14</sup>

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<sup>10</sup> *Ibid.*, at 49.

<sup>11</sup> *Ibid.*, at 25.

<sup>12</sup> EB-2009-0084, OEB Staff Report, January 14, 2016, at 1.

<sup>13</sup> EB-2010-0008, Decision with Reasons, March 10, 2011, at 116.

<sup>14</sup> *Ibid.*, at 117.



### EB-2013-0321

In EB-2013-0321, the OEB found that OPG's business risks had changed, primarily pointing to the addition of 48 hydroelectric assets to OPG's regulated assets and the then recently completed Niagara Tunnel Project. Specifically, the OEB found that the addition of hydroelectric assets and the Niagara Tunnel Project "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."<sup>15</sup>

As a result of these findings, the OEB lowered the equity ratio for OPG from 47% to 45%. Specifically, the OEB stated, "...[t]he Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."<sup>16</sup>

In addition, the OEB found that, at the time of EB-2013-0321, moving to incentive regulation did not significantly increase risks to OPG such that the capital structure should be reset, noting that the capital structure for Ontario's electricity and gas distributors had not been reset when they moved to incentive regulation. The OEB did note, however, that part of its decision was based on the fact that OPG was not moving to incentive regulation in EB-2013-0321, and that "any potential changes to business risk this may entail could be considered in the incentive regulation proceeding."<sup>17</sup>

### EB-2016-0152

The OEB left OPG's equity ratio unchanged in its decision and order in EB-2016-0152. The OEB continued to find that nuclear generation presents more business risks than hydroelectric generation, and that OPG's nuclear rate base would "increase substantially over the five-year term of [of the period over which rates were being set],"<sup>18</sup> but noted that nuclear generated MWh will not increase relative to hydroelectric MWh. The OEB further found that OPG's nuclear-specific risks were mitigated by factors including "various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG to recover substantially all their unexpected or unforeseen costs."<sup>19</sup> The OEB also found that the move to incentive regulation would not add significant risk to OPG noting that there was no new evidence to the contrary, and that given OPG's planning of the DRP and certain regulatory protections under O. Reg. 53/05, the risks of the DRP were also controlled. Additionally, the OEB commented on the use of U.S. companies in the proxy group for OPG, noting that Canadian

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<sup>15</sup> EB-2013-0321, Decision with Reasons, November 20, 2014, at 113. Clarification added.

<sup>16</sup> *Ibid.*, at 114.

<sup>17</sup> *Ibid.*

<sup>18</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.

<sup>19</sup> *Ibid.*



ratemaking equity ratios tend to be lower than U.S. ratemaking equity ratios and that, in EB-2016-0152, an adjustment should have been made to the U.S. companies' equity ratios to account for that divergence. The OEB also noted that given its findings in the decision related to OPG's plan for Pickering extended operations beyond 2020 and the regulatory protections under O. Reg. 53/05, the associated risks, including a determination that Pickering extended operations may not proceed, were unlikely to materialize.



## SECTION 4: PRINCIPLES FOR A FAIR RETURN

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The Supreme Court of Canada established the principles surrounding the concept of a “fair return” for a regulated company in the *Northwestern Utilities v. City of Edmonton* (1929) (“Northwestern”) case, where the Supreme Court found:

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*By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company’s enterprise.<sup>20</sup>*

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As stated by Major and Priddle in 2008, this definition remains in full legal effect today.<sup>21</sup>

United States law regarding fair return for utility cost of capital has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court found:

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*The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*

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The U.S. Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). There the Court described the relevant criteria as follows:

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*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock [...] By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to*

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<sup>20</sup> Northwestern at 193.

<sup>21</sup> The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications, by The Honourable John C. Major, Former Justice, Supreme Court of Canada, and Roland Priddle, President, Roland Priddle Energy Consulting Inc., Former Chair of the National Energy Board, March 2008, at 4.



*assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

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With the passage of time, the fair return standard has been interpreted many times in both Canada and the U.S. In Canada, the National Energy Board (“NEB”, predecessor to the Canadian Energy Regulator) summarized its interpretation of the “fair return standard” in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its Trans Québec & Maritimes Pipelines Inc. RH-1-2008 Decision, at pp. 6-7.

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*The [NEB] is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*

- *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
- *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*

*In the [NEB]’s view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline’s revenue requirement, result in tolls that are just and reasonable.<sup>22</sup>*

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Similarly, in its EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, the OEB discussed the necessity of adhering to the fair return standard as follows:

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*The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed*

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<sup>22</sup> National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.



*judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*

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*... all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].<sup>23</sup>*

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Canadian regulatory authorities, including the OEB, have also determined that another key principle in establishing a fair return on equity for a regulated utility is the “stand-alone” principle. The OEB’s specific findings with regard to the stand-alone principle for OPG are included above in the summary of EB-2007-0905.

Furthermore, the OEB has recognized that the cost of capital is a forward-looking concept. For example, in its decision in EB-2009-0084, the OEB referenced a presentation by Dr. Bill Cannon at CAMPUT’s 2009 Energy Regulation Conference during which Dr. Cannon explained the forward-looking nature of the cost of capital as follows: “First, it [the cost of capital] is forward looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return.”<sup>24</sup> Elsewhere in that same decision, the OEB stated: “First, the Board notes that the [Fair Return Standard] expressly refers to an opportunity cost of capital concept; one that is prospective rather than retrospective.”<sup>25</sup> In other words, investors establish their return requirements based on expectations regarding economic growth, inflation, interest rates, the market risk premium and other factors affecting future risks and opportunity costs.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the OEB has expressed its view that “the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a

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<sup>23</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, at i and 19.

<sup>24</sup> *Ibid.*, at 25.

<sup>25</sup> *Ibid.*, at 19.



long-term sustainable basis given the opportunity costs of capital.”<sup>26</sup> Further, the OEB has determined that “[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities.” However, the assessment of comparability “does not require that those entities be ‘the same’.”<sup>27</sup>

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<sup>26</sup> *Ibid.*, at 20.

<sup>27</sup> *Ibid.*, at 21.



## SECTION 5:

# CANADIAN VERSUS U.S. HISTORICAL EQUITY RATIOS

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In its EB-2016-0152 decision and order, the OEB determined that “on balance an increase in OPG’s equity thickness is not necessary in order for the fair return standard to be met.”<sup>28</sup> With respect to the information presented by both Concentric (on behalf of OPG) and the Brattle Group (on behalf of the OEB Staff) regarding the allowed equity ratio for the U.S. proxy group and the authorized equity ratios for Canadian investor-owned utilities, the OEB wrote: “The OEB finds that an adjustment to the comparator group data should have been made by both experts to account for the substantially lower common equity ratios allowed regulated utilities in Canada.”<sup>29</sup>

In considering this matter in this report, Concentric’s analysis is that while the average allowed equity ratio for U.S. utilities is higher than the average deemed equity ratio for Canadian utilities, this wide differential is not currently explained by differences in business risk, including regulatory risk. For example, equity and credit analysts have acknowledged that while they previously considered U.S. utilities to have higher business and regulatory risk than Canadian regulated utilities, that perception has changed in recent years as U.S. utilities have been granted a broader suite of cost recovery mechanisms and adjustment clauses that reduce regulatory lag and provide similar risk mitigation to that of their Canadian counterparts. Equity analysts have also indicated that they view the regulatory environment in Canada and the U.S. as being similar, and that U.S. regulation has been providing more timely cost recovery and reducing regulatory lag in recent years.

For example, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

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*Historically, the Canadian utilities have traded at a discount to their mid-cap U.S. peers. We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view) as well as to strong earnings growth in part due to M&A.*<sup>30</sup>

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This continues a trend that started approximately ten years ago. For example, in a September 2013 report, Moody’s Investors Service (“Moody’s”) explained its changing view on the relative risk of U.S.

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<sup>28</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 109.

<sup>29</sup> *Ibid.*

<sup>30</sup> Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9. Emphasis added.



and Canadian utilities as follows:

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*Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.<sup>31</sup>*

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In support of this changing view on the relative risk of the US regulatory environment, Moody's noted the following developments:

- “We believe that many US regulatory jurisdictions have become more credit supportive of utilities over time and that the assessment of the regulatory environment in the US that has been incorporated in the ratings may now be overly conservative.”<sup>32</sup>
- “While we had previously viewed individual state regulatory risks for US utilities as being higher than utilities in most other developed countries (where regulation usually occurs at the national level), we have observed an overall decrease in regulatory risk in the US.”<sup>33</sup>
- “There have been a number of favorable regulatory changes in recent years. For example, the increasing prevalence of riders, trackers and other automatic cost recovery provisions in the US has reduced the amount of time between when a utility incurs and recovers costs, or ‘regulatory lag.’ These changes have happened incrementally – jurisdiction by jurisdiction or even issuer by issuer. We now believe that these changes, in aggregate, represent a significant improvement in the timeliness of cost recovery.”<sup>34</sup>
- “We believe the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states while balancing the needs of the state’s commercial, industrial and residential utility customers.”<sup>35</sup>
- “A comparison of key financial ratios used under the Regulated Electric and Gas Utilities Rating Methodology in rating utilities across developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan) shows that US regulated

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<sup>31</sup> Moody's Investors Service, Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation, September 23, 2013, at 1.

<sup>32</sup> *Ibid.*, at 4.

<sup>33</sup> *Ibid.*

<sup>34</sup> *Ibid.*

<sup>35</sup> *Ibid.*



utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers.”<sup>36</sup>

In order to supplement our assessment of how investors perceive the regulatory environment for utilities in Canada and the U.S., Concentric conducted interviews in October and November 2020 with equity and credit analysts who cover the North American utility industry to discuss their views regarding the regulatory environment in Canada and the U.S.<sup>37</sup> The interviews focused on the following questions: 1) whether the analysts factor country risk into their analysis/rating; 2) whether they see the Canadian regulatory environment as providing any more or less risk protection and support to utilities than the U.S. regulatory environment, and if so, what specific factors lead to this conclusion; 3) whether they factor in state/provincial level regulatory risk in their analysis; 4) whether they view the Ontario regulatory environment as more or less favorable than other Canadian provinces and U.S. states; 5) whether they view electric generation as more or less risky than electric transmission and distribution (“T&D”); 6) whether they view nuclear generation as more or less risk than other types of electric generation; and 7) whether they see differentials in equity ratios between Canadian and U.S. utilities as being justified by differences in business and regulatory risk in Canada or Ontario as compared to the U.S.

Importantly, while many analysts continue to view the Canadian regulatory environment as somewhat more favorable for regulated utilities than the U.S. regulatory environment, the situation in Canada is seen as being static, while the U.S. landscape is viewed as having improved in recent years through the more frequent use of forward test years, revenue decoupling mechanisms, and capital cost recovery mechanisms that have reduced regulatory lag and enhanced the ability of U.S. utilities to earn their authorized ROE. Further, equity and credit analysts do not see the differential in deemed equity ratios between Canada and the U.S. as being justified by differences in business or regulatory risk. In addition, it was clear from our interviews that equity and credit analysts see the utility industry as a North American industry, and that any differences are more likely to be observed between specific provinces/states than between the two countries. The differences between specific provinces and states are viewed as being very narrow, and most Canadian provinces and U.S. states are seen as credit supportive for regulated utilities, with only minor gradations between those that are most credit supportive and those that are less credit supportive. Lastly, equity and credit analysts

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<sup>36</sup> *Ibid.*, at 5.

<sup>37</sup> Survey participants included: Robert Hope, equity analyst – Scotiabank; Robert Kwan, equity analyst – RBC Capital Management; Ben Pham, equity analyst – Bank of Montreal; Andrew Ng, Gerrit Jepsen, and Obioma Ugboaja, credit analysts – S&P Global Ratings; and Gavin MacFarlane, credit analyst – Moody’s Investors Service



agreed that ownership of electric generation assets is more risky than electric transmission and distribution operations, and that nuclear generation is the riskiest type of generation. The last finding is further supported by Appendix A, in which excerpts from S&P Global Ratings (“S&P”) reports illustrate that agency’s views on the high-risk nature of nuclear operations.

The following section provides more specific details regarding how the analysts we interviewed view the risk profiles of the utilities they cover and the regulatory environment in which those utilities operate.

Country risk: Equity and credit analysts who participated in the survey indicated that they view Canada and the U.S. as having the same or very similar country risk. They do not distinguish between the two countries on the basis of country risk unless there is a large divergence in the risk-free rate (i.e., wider than the current gap of 20 basis points for the 10 year government bond). They tend to consider country risk as a factor in their investment analysis when they are comparing Canada and the U.S. to other countries outside North America, in particular emerging markets.

Comparing Canadian and U.S. regulatory environment: Equity and credit analysts tend to see the Canadian regulatory environment as somewhat more favorable than in the U.S. However, most analysts noted that the U.S. regulatory environment has improved in recent years U.S. due to the increased use of forward test years, revenue decoupling mechanisms, and approval of cost recovery mechanisms that improve the timeliness of cost recovery for capital investments and infrastructure replacement projects. Several analysts expressed the view that it is more important to consider differences between specific jurisdictions instead of drawing more general conclusions about the two countries. Also, it was observed that the regulatory environments in Canadian provinces are more homogeneous than in the U.S., and that there are a number of U.S. jurisdictions that compare favorably to Canadian jurisdictions in terms of providing support for timely cost recovery and the ability to earn the authorized return. Credit analysts in particular were more focused on whether the regulatory environment provided regulatory and financial stability, and whether there was regulatory independence and a lack of political interference, than on whether one jurisdiction was more supportive than another. Equity analysts tended to focus on whether the utility is able to earn its authorized return and generate predictable earnings and cash flows. One analyst commented that he believes the higher authorized ROEs in the U.S. help to offset the greater regulatory lag in certain states. The prevalence of cost disallowances was another factor noted by both equity and credit analysts as a consideration (and as a concern for OPG in particular).

Influence of regulatory risk on investment analysis: One equity analyst observed that utilities in more favorable jurisdictions receive higher valuations, while those in less favorable jurisdictions receive lower valuations. Another equity analyst indicated



that his firm's top utility recommendation was a Canadian company that had more than half its assets in a U.S. subsidiary that operates in a state that allows relatively high ROEs, support for rate base investment, and strong customer relationships that result in settlement agreements. At the same time, they have a less favorable outlook on another Canadian utility company given its material exposure to a jurisdiction that has among the lowest authorized ROEs in the country and stranded asset risk. Credit analysts reiterated their view that differences in regulatory risk between jurisdictions were relatively small and that regulation provides an overall credit supportive environment for all utilities in both Canada and the U.S.

Equity ratio differential: The equity analysts expressed the view that the equity ratio differential between Canada and the U.S. is not justified by differences in business or regulatory risk between the two countries. In particular, one equity analyst commented that the equity thickness and ROE in Ontario are inferior to many other jurisdictions, especially those in the U.S. While this difference historically was acceptable, the analyst saw the improving regulatory framework in the U.S. as cause for concern that the low equity thickness and ROE in Ontario could lead to challenges in incenting capital to flow to the province. Another equity analyst observed that the equity thickness gap has not narrowed between Canada and U.S., and that he would prefer that the equity ratio gap be lowered.

Generation vs. T&D operations risk: The equity and credit analysts who we interviewed agreed that companies that own electric generation assets have greater risk than T&D utility companies. Among the reasons cited for this higher risk profile were: increased operational risk, greater risk of economic obsolescence, higher risk of forced outages, and higher environmental risk. An equity analyst commented that with the emergence of environmental, social and governance ("ESG") considerations in late 2018, investors now tend to prefer companies with less generation and more T&D assets. A credit analyst explained that generation has higher risk under their stated credit criteria, and that generation ownership specifically affects the financial risk profile of a utility company because it determines what financial benchmarks are used to assess financial risk.

Nuclear risk: Nuclear generation is viewed as the riskiest type of generation by the equity and credit analysts we interviewed. Among the reasons for this assessment were: the possibility of catastrophic failure and loss of life, damage to the environment, risk around decommissioning and spent fuel disposal, construction cost overruns, more unplanned outages, negative sentiment around the technology following the nuclear incident in Japan, and higher safety requirements. One equity analyst commented that the Ontario government has been supportive of nuclear generation being part of the fuel mix, as evidenced by the ongoing refurbishment of the Darlington and Bruce reactors, and that the risk of economic obsolescence is generally lower for nuclear as compared to other generation types. Another equity analyst indicated that certain investors have investment policy statements that



restrict any exposure to nuclear energy. Lastly, a credit analyst expressed the view that nuclear risk is company specific and that state legislation to support nuclear capital cost recovery does not always provide protection depending on the company's circumstances.

The results of the analyst interviews support Concentric's view that an adjustment for differences in the allowed equity ratios between Canada and the U.S. would be inconsistent with the market's current views, namely that cross-border business and regulatory risk for regulated utilities in the two countries is comparable. As such, Concentric believes that the historical differential between authorized equity ratios in Canada and the U.S. cannot be currently applied on the basis of differences in these risks and that it is appropriate to compare OPG's allowed equity ratio to that of risk comparable utilities in both countries without adjustment when setting OPG's regulatory capital structure on a forward-looking basis.



## SECTION 6: CHANGES IN CAPITAL MARKETS SINCE THE EB-2016-0152 DECISION AND ORDER

Capital markets impact the appropriate regulatory capital structure as they have a direct impact on the required ROE that, when combined with the equity ratio, determines the allowed return on equity. Since the OEB's last major decision on OPG's payment amounts (EB-2016-0152) in December 2017, and through the early months of 2020, North American capital markets reflected a period of slow economic growth, coupled with low inflation and historically low government bond yields. Stock markets in both the U.S. and Canada responded with continued growth in the major indices as investors grew comfortable with the prospects for slow but steady economic growth and improving corporate profitability. That, of course, all changed in March 2020 with the onset of the COVID-19 pandemic and upheaval of the global economy. In response, stock prices declined sharply, before subsequently beginning to recover, and stimulative economic policies have pressed government bond yields even lower. These fundamental market indicators are captured in Figure 4 below.

**Figure 4: Capital Market Trends 2017-2020**

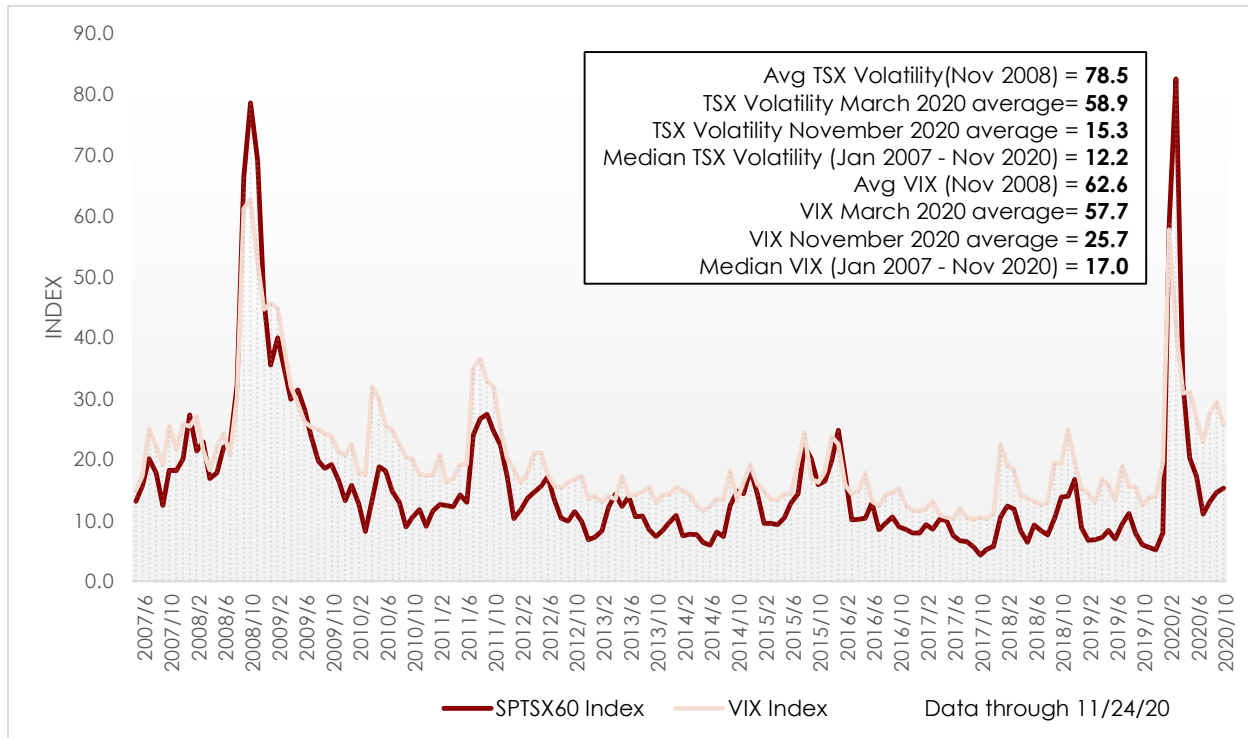
Description	2017	2018	2019	YTD 2020	Current (12/24/2020)	Source
TSX Index	15,545	15,738	16,317	15,999	17,624	[1]
S&P 500 Index	2,448	2,744	2,912	3,210	3,703	[1]
30-Year Bond Yield (Canadian)	2.28%	2.36%	1.80%	1.22%	1.26%	[1]
30-Year Bond Yield (U.S.)	2.89%	3.11%	2.58%	1.56%	1.66%	[1]
10-Year Bond Yield (Canadian)	1.79%	2.28%	1.59%	0.76%	0.72%	[1]
10-Year Bond Yield (U.S.)	2.33%	2.91%	2.14%	0.89%	0.92%	[1]
30-Year Utility Bond Yield (Canadian)	3.65%	3.74%	3.30%	2.78%	2.62%	[1]
30-Year Utility Bond Yield (U.S.)	4.01%	4.25%	3.78%	2.99%	2.73%	[1]
Real GDP Growth (Canadian)	3.04%	2.43%	1.86%	-6.18%	-3.44%	[2]
Real GDP Growth (U.S.)	2.33%	3.00%	2.16%	-4.13%	-2.18%	[3]
Notes:						
[1] Source: Bloomberg Professional; Values reflect average over indicated period						
[2] Source: Statistics Canada. Table 36-10-0104-01 Gross domestic product, expenditure-based, Canada "Current" value compares 2020 Q3 value to 2020 Q1 value with no annualization						
[3] Source: Bureau of Economic Analysis, Table 1.1.6. Real Gross Domestic Product "Current" value compares 2020 Q3 value to 2020 Q1 value with no annualization						

As investors have been adapting to the new norms of the pandemic, stock markets have surpassed pre-pandemic levels, as government bond yields remain at or near newly established historic lows.



Although one could conclude that the cost of equity for utilities is lower in such an environment, there is evidence to the contrary. In particular, equity markets remain in a heightened state of volatility, as seen below.

**Figure 5: Equity Market Volatility 2007-2020<sup>38</sup>**



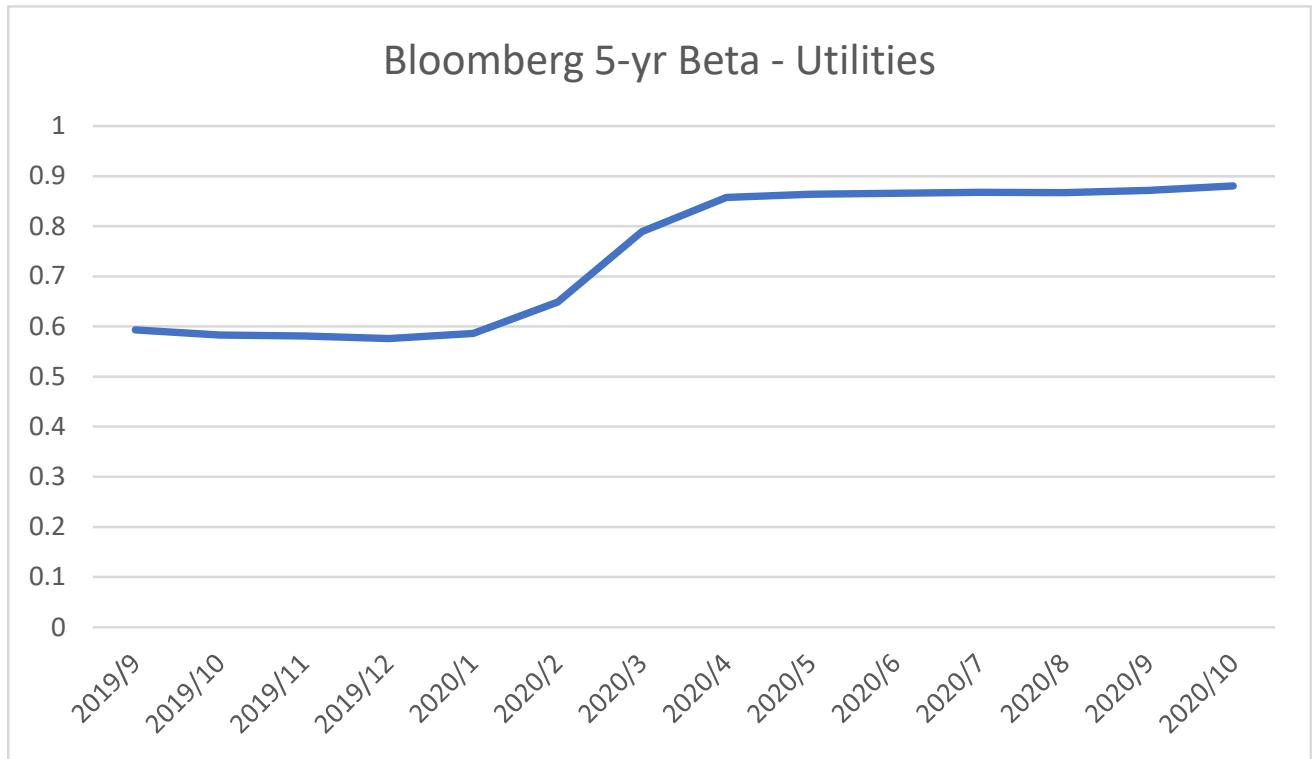
Stock market volatility for both the TSX60 and S&P500 (as measured by its volatility index, or “VIX”) are presented. The spike that occurred in March 2020 was unprecedented, and even though markets have since then stabilized, volatility remains above historical levels for the past two decades. Higher volatility is generally considered a sign of increased risk in the broad markets.

Looking at utilities specifically, Figure 6 below illustrates a significant upshift in the betas for utility stocks over the past twelve months, centered in the March/April 2020 timeframe. Beta is broadly considered a measure of risk, and this upward shift in utility betas signals that investors are not considering utilities at the same low levels of relative risk as they have in the past. In the context of the current pandemic, we believe this is likely driven, at least in part, by an uncertain economic outlook and a recognition that even regulated utilities face increased risk exposure in the current and foreseeable environment.

<sup>38</sup> Source: Bloomberg Professional. Data for 2020 updated through November 24, 2020.



**Figure 6: Utility Stock Betas – Sept. 2019 through Oct. 2020**



The above trend is unlike prior periods of market disruption where utilities have typically served as a safe haven for investors. It appears that the pandemic has left investors uncertain of the outlook for the sector amid concerns for slumping demand and disruption to business plans, with utility betas in both the U.S. and Canada increasing substantially since January 2020. This indicates that the cost of equity for regulated utilities has increased. In contrast, when the OEB recently updated the cost of capital parameters for the 2021 rate year, the authorized ROE was reduced from 8.52% to 8.34% due to the decline in the government bond yields. Notably, this currently places the allowed ROE in Ontario below that of any other North American regulatory jurisdiction and negatively affects OPG's credit metrics at a time when they are already expected to be pressured.



## SECTION 7: CHANGES IN BUSINESS AND FINANCIAL RISKS SINCE THE EB- 2016-0152 DECISION

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Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. Financial risk relates to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

The cost of capital is a forward-looking concept, and utility investors tend to be long-term providers of capital. For these reasons, it is important to not only review OPG's current business and financial risk profile, but also to assess how that risk profile has changed and will change going forward. This approach is consistent with the OEB's findings in prior decisions regarding OPG's capital structure.<sup>39</sup>

This section contains an overview and analysis of OPG's business and financial risks, with a focus on how those risks have changed since EB-2016-0152 and how they are forecast to change over the 2022 to 2026 rate-setting period.

To evaluate OPG's business risks, Concentric performed an independent review of OPG and its regulatory environment, building on Concentric's previous assignment in EB-2016-0152. The review included: (1) risks related to the prescribed hydroelectric facilities; (2) risks related to the prescribed nuclear facilities, including the DRP and upcoming retirement of the Pickering station; (3) OPG's projected regulated business mix between those two types of generation, and how that mix is expected to change over the rate-setting period; and (4) the external influence of climate change and its impact on OPG's generation fleet and operations.

Our experience in assessing business and financial risks and the effect on the cost of capital in Ontario and other regulatory jurisdictions, as well as our prior roles as an independent monitor and advisor to the power industry, informed our review. Our additional experience advising buyers and sellers of generation facilities, including hydroelectric and nuclear facilities, further informs our views on the investor perspective regarding the business risk of these assets. Our evaluation process included research on equity and credit analyst views regarding OPG and the regulated generation industry,

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<sup>39</sup> For example, in EB-2013-0321, the Board determined that because the business risk for OPG's regulated operations had changed in the specific payment-setting period in that proceeding, the capital structure should reflect that change.



relevant industry data, other publicly-available materials such as Ontario's December 2017 Long-Term Energy Plan and the IESO's 2020 Annual Planning Outlook, regulatory filings made by OPG, OPG's Amended 2020-2026 Business Plan, OPG's financial reports, OPG's Climate Change Plan and interviews with OPG subject matter experts.

Concentric concludes in this section that while OPG's risk level for its regulated operations will remain the same in some areas of the business, the overall risk for these operations will significantly increase, due to the following factors:

- OPG continues to be at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators. This risk pervades and compounds OPG's other nuclear risks, discussed below.
- The DRP, as OPG is entering a period of acute risk beyond what it has experienced historically, with three units coming offline in the upcoming rate setting period with overlapping outages, new FOAK scope being added to the refurbishment, competition for resources with the Bruce Power refurbishment, and ongoing constraints and risks presented by the COVID-19 pandemic;
- The majority of OPG's nuclear fleet is nearing the end of its current operating life, with Pickering planned to end commercial operation during this upcoming rate period and Darlington units requiring refurbishment as they reach their end of 'first' life. Therefore, OPG is at inherently higher risk related to variability in the generation output due to the aging of the nuclear stations. This could lead to significant revenue shortfalls for OPG;
- In addition to the increased generation risk leading up to the end of the station's commercial operations, the shutdown and retirement of Pickering, comprising six of the Company's ten operating nuclear reactors and served by thousands of employees, in this upcoming rate period presents new and unique challenges for OPG related to disruptive organizational changes that can impact operational performance, increased forecast risk and reduce the diversification of OPG's nuclear fleet;
- Risks to both OPG's nuclear and hydroelectric operations from climate change have increased considerably from its prior rate proceeding, including the risk of increased capital expenditure needs due to the threat of climate driven impacts on the company's infrastructure and systems;



- OPG's asset mix will continue to shift towards a higher proportion of riskier nuclear assets, combined with an increase in relative value of each nuclear MWh due to declining generation over which revenue requirement is recovered on a variable basis; and
- OPG's financial risk will increase in the period from 2022 to 2026, as illustrated by the pressure on, and potential decline below current credit rating thresholds of, key credit metrics in the earlier years of the rate setting period.

Concentric concludes that, taken as a whole, this shift in risk profile is sufficient to warrant a reassessment of OPG's equity ratio.

### **OPG Overview**

OPG is an electricity generation company established under the Ontario Business Corporations Act and is wholly owned by the Province of Ontario ("Province"). As of December 31, 2019, OPG's regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington) as well as 54 hydroelectric generating stations. OPG's regulated facilities are the prescribed facilities under O. Reg. 53/05.

Since 2017, OPG is a public debt issuer in Canada. OPG, as a corporation, has a split "A (low)" issuer and unsecured debt rating (with stable trend) (as of April 16, 2020) from DBRS Morningstar ("DBRS"), a "BBB+" issuer and unsecured debt credit rating (with stable outlook) (as of July 17, 2020) from S&P, and an "A3" senior unsecured debt rating from Moody's (with stable outlook) (as of December 21, 2020).

Both S&P and Moody's note that they rate OPG three notches below their respective OPG corporate credit ratings on a stand-alone basis (that is, before considering support by the Province), namely as "BB+" and "baa3", respectively.

### **Changes in Business Risk**

#### **1. Hydroelectric Facilities**

OPG has 54 hydroelectric stations that are subject to OEB regulation and that supply approximately 6,400 MW of generating capacity. The remainder of OPG's hydroelectric stations are not regulated by the OEB. The hydroelectric system is comprised of a diverse set of assets. OPG's hydroelectric stations vary in size, location, age, operating and hydrological characteristics (*i.e.*, base load, intermediate, peaking). Because of the geographic diversity of the system, the hydroelectric assets are subject to numerous federal, interprovincial, and provincial regulations, international treaties, agreements, and waterpower leases. OPG plans to invest approximately \$2.0 billion of capital in its



hydroelectric system over the 2022 to 2026 period. Those investments are being made primarily to replace aging infrastructure and upgrade/redevelop certain sites.

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

OPG's hydroelectric business is expected to remain relatively stable from an operating risk perspective relative to the experience and conditions as they existed at the time of EB-2016-0521, subject to the impact of climate change impacts and increased inflationary risk, as discussed further below.

OPG's hydroelectric operations are subject to variances in water flow and surplus baseload generation ("SBG") curtailments. However, while the availability of water to power the stations can vary significantly from year to year, Concentric is not aware of any reason why variances in water flow over the rate period are more or less at risk of being higher or lower than at the time of EB-2016-0152 (subject to the climate change risk discussed below). In addition, with respect to SBG, Concentric understands that a reduction in nuclear generation capacity in the Province through the period of refurbishments and Pickering retirement is generally expected to result in a gradual decline in SBG conditions, although this may be offset by inherent near-term risks to electricity demand associated with the COVID-19 pandemic.

Further, OPG has a Hydroelectric Water Conditions Variance Account that records and mitigates the financial impact of differences between forecast and actual water conditions, and a Hydroelectric Surplus Baseload Generation Variance Account that records and mitigates the financial impact of SBG related curtailments, subject to the OEB's approval. On balance, Concentric is of the view that the risks related to the availability of water to power the stations and SBG related curtailments have not changed significantly since EB-2016-0152. Concentric understands that OPG's rate application will propose that these and other currently-approved deferral and variance accounts related to its prescribed hydroelectric facilities remain in place. Assuming this proposal is approved, there should be no overall change in risk for OPG.



Similar to the risks related to the availability of water flows, Concentric is not aware of any significant changes in risks related to water management and environmental regulations affecting OPG's regulated hydroelectric power production relative to the risk levels at the time of EB-2016-0152.

OPG's hydroelectric system is a mature system, with an average age of approximately 80 years and the oldest facility being over 120 years old. 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 generally lower than it would be for a newer system. In addition, Concentric understands that OPG is not planning to add any significant amount of new hydroelectric capacity during the period, beyond upgrading or redeveloping certain existing sites. Because of this, Concentric expects OPG's need to obtain waterpower leases or rights for new regulated hydroelectric capacity should not materially deviate from recent experience, leaving associated risks at similar levels as at the time of EB-2016-0152.

OPG's hydroelectric base payment amounts are legislatively set at the 2021 amount and as such will not increase over the 2022-2026 period. As a result, OPG will be exposed to a level of incremental inflationary risk over the upcoming period, relative to a hydroelectric payment amount set under a price-cap incentive regulation model applied in EB-2016-0152.

Based on the above, Concentric concludes that although some incremental risks have emerged, OPG's operational risks and regulatory risks related to its prescribed hydroelectric facilities have not changed significantly since EB-2016-0152, other than additional risks from rising threat of climate-driven impacts (discussed further below) and incremental inflationary risk.

## **2. Nuclear Facilities**

OPG has two prescribed nuclear facilities: Darlington and Pickering. Operating since the early 1990s, Darlington is a CANDU, four-unit station with a generating capacity of about 3,500 MW. Pickering has been in operation since the early 1970s and is a CANDU, six-unit station with a generating capacity of about 3,100 MW, with two additional units in a permanent safe shutdown state. OPG's nuclear operations, including nuclear waste management activities, are subject to federal regulation by the Canadian Nuclear Safety Commission ("CNSC") on all matters pertaining to the development, production and use of nuclear energy, including matters of safety, security and the environment. Supported by the Province, OPG plans to operate Pickering Units 1 and 4 to 2024 and, subject to CNSC's regulatory approval, Units 5-8 until the end of 2025, under an optimized shutdown schedule. The current CNSC operating licence for the Darlington station expires on November 30, 2025 and for the Pickering station on August 31, 2028. The Pickering operating licence currently allows



commercial operation of the station until December 31, 2024. All of OPG's operating licences for its nuclear waste facilities are also current and up to date.

OPG's sustaining capital investment program for the nuclear fleet is primarily focused on ensuring the Darlington station is well positioned to transition to steady state 'second life' operations following refurbishment, including investments in life cycle and aging management projects, facility upgrades and work in support of regulatory commitments. Over the 2022 to 2026 period, OPG plans to make sustaining capital investments totaling approximately \$1.8 billion into the nuclear fleet, in addition to the DRP.

OPG is responsible for the ongoing and long-term management of nuclear fuel and other nuclear waste from its operations as well as for the eventual decommissioning of its nuclear generating stations and waste management facilities. Under the Ontario Nuclear Funds Agreement ("ONFA") with the Province, OPG is required to set aside funding in segregated funds toward the long-term management of nuclear waste and decommissioning obligations. Subject to certain exposures assumed by the Province, OPG bears the risk of future cost increases and fund investment performance related to these obligations. Canada's plan for long-term management of spent nuclear fuel is being implemented by a federally-mandated organization, established and funded by nuclear fuel owners including OPG. OPG is responsible for a plan for long-term disposal of its low and intermediate level waste material.

Under the current rate plan, OPG recovers the cost of its nuclear facilities under a custom incentive rate-setting ("Custom IR") framework established in EB-2016-0152. Under the Custom IR framework, OPG continues to be at risk related to the variability in the generating output of its nuclear facilities. OPG's risk related to the variability in nuclear generating output compounds its nuclear-specific business risks, as discussed herein, and also distinguishes OPG from other regulated North American generators.

Generally, the major risks to a regulated utility related to nuclear power generation include: (1) the ability to implement large and complex projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at risk of producing lower-than-forecasted power; (4) retirement and decommissioning of nuclear plants and long-term management of spent nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.



Consistent with the OEB's prior findings, nuclear generation is viewed by the investment community to be riskier than other forms of generation, including hydroelectric generation.<sup>40</sup> Furthermore, for large nuclear construction projects, regulatory support for timely cost recovery is critical given the complexity of building this type of generation, as highlighted by a history of industry project delays and cost overruns, as well as a shortage of skilled labor.<sup>41</sup> Appendix A provides additional information regarding the investment community's views on the high-risk nature of nuclear operations.

Before turning to the changes in OPG-specific nuclear risks, we note that recent events in the nuclear construction business since EB-2016-0152 have further raised the perceived risk of large nuclear facility projects among investors and credit rating agencies. In particular, two new nuclear projects in the U.S. (*i.e.*, the Vogtle Plant in Georgia and the now-cancelled Summer Plant in South Carolina), both of which were being pursued under favorable legislative and regulatory frameworks, have run into cost and schedule issues. One of the projects (*i.e.*, the V.C. Summer plant in South Carolina) resulted in the bankruptcy of a major vendor, the downgrading of the credit rating of the owners, the eventual merger of one of the owners (*i.e.*, SCANA Corporation) into a larger utility (*i.e.*, Dominion Energy), and the potential to require the sale of the other owner (*i.e.*, Santee Cooper, a state-owned corporation) to an investor-owned utility in order to eliminate a reported billions in interest charges to customers for a plant that was never completed. These projects and their regulatory and political environment are discussed in greater detail in a subsequent section of the report.

The major changes in the operational and financial risks faced by OPG's nuclear facilities are as follows:

#### **a. Darlington Refurbishment**

OPG is refurbishing the Darlington station for 30-plus additional years of operations. The four-unit DRP is a "megaproject" with a budget of \$12.8 billion, lasting approximately a decade in execution.

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<sup>40</sup> See, *e.g.*, Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017, at 42-43, in which Moody's highlighted risks related to nuclear ownership that include: (1) safety, regulatory, and operational issues; (2) lasting regulatory and safety consequences from the March 2011 Fukushima nuclear accident in Japan, leading to increased operating costs; and (3) an aging fleet and early retirements due to station failures that require uneconomic repairs.

<sup>41</sup> In its 2013 rating methodology for utilities, Moody's also commented on legislative and regulatory support for nuclear construction projects, noting specifically SCANA Corporation in South Carolina: "For SCANA Corporation, the South Carolina Base Load Review Act provides strong credit support for companies engaging in nuclear new-build, which also affects the scoring for consistency and predictability of regulation. However, SCANA's rating also considers the size and complexity of the nuclear construction project, which is out of scale to the size of the company, as well as structural subordination." Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 43.



At the time of writing, OPG had completed the refurbishment of the first unit, Unit 2, and has commenced the refurbishment of the second unit, Unit 3. The remaining two units are scheduled to commence execution early in the 2022 to 2026 period, with the entire project completed by the end of 2026. Capital expenditures totaling approximately \$4.8 billion were placed in service upon Unit 2 returning to service, including overall DRP definition phase costs incurred prior to commencement of execution.

**i. DRP Risk Profile**

A project of the DRP's size and schedule length that will more than double OPG's rate base, regardless of the technology, inherently presents a significant source of risk for any utility. As noted in the Scope of Analysis and Overview of Concentric section of this report, Concentric has been an advisor to several North American utilities undertaking "megaprojects" such as the DRP. We have witnessed firsthand the issues even the most well-planned large construction projects can face, including scope, budget, and schedule increases, as well as increased regulatory scrutiny. The performance of large construction projects in a nuclear setting compounds those issues.

Specifically, the DRP includes multiple complex work packages, including the removal and replacement of the reactor calandria tubes and pressure tubes from each reactor, replacement of all feeders, refurbishment of the existing fuel handling equipment, refurbishment of the existing turbine generators, refurbishment of the existing steam generators, and a set of supporting refurbishment projects aligned with existing station systems. The project involves numerous third-party vendors and the coordination of multiple scopes of work, all within the highly regulated and safety-conscious environment of a nuclear facility. In addition, the Canadian marketplace for nuclear construction firms is limited, increasing the risks related to vendor management and performance. Furthermore, the DRP is currently being executed during the global COVID-19 pandemic, which places constraints on and could pose additional risks for the project, as further discussed below.



The inherently high execution risks associated with the DRP have been noted by the investment community. For example, Moody's stated in its December 2020 OPG credit rating report, "[t]he company is also pursuing a CAD12.8 billion nuclear refurbishment project across 4 units at its Darlington nuclear generation station that carries a very high level of execution risk."<sup>42</sup> Similarly, DBRS observed in its April 2020 OPG credit rating report, "[t]he Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale."<sup>43</sup> In EB-2016-0152, the OEB similarly stated that, "[t]here is no question that successful execution of the DRP is a challenge for OPG during the term of [the 2017-2021 rate] plan."<sup>44</sup>

OPG successfully completed the refurbishment of Unit 2 earlier in 2020, which has been positively noted by the credit rating agencies. For example, S&P stated in its July 2020 OPG credit rating report, "[t]he company's on-time and on-budget record [on Unit 2] increases our confidence that the other three units will be also be completed without incurring project delays or materially higher costs."<sup>45</sup> However, it is known that prior CANDU refurbishments and large nuclear construction projects in the U.S. have encountered significant challenges. As demonstrated by those prior projects, schedules can slip, outage durations can be different than expected, and there are risks related to the performance and output of the nuclear facilities post-refurbishment.

While OPG has carefully planned the refurbishment of the three remaining units, including applying lessons learned from the Unit 2 refurbishment, Concentric concludes that there are a number of additional risks that the Company is facing during the remaining project period, as discussed below. In Concentric's opinion, notwithstanding a decrease in certain risks resulting from the experience gained on Unit 2, the additional risks result in an overall increase to the Company's risk profile as it relates to the remainder of the project.

First, the DRP is entering a period of acute execution risk beyond what it has experienced historically. The refurbishment of Unit 2 took place when there were no other units undergoing refurbishment in Ontario. In contrast, three of the Darlington units are planned to be offline for refurbishment during the upcoming rate setting period. Critically, the refurbishments for the units will overlap; for a period of time in 2023 all three units are planned to be offline. Also during OPG's upcoming rate setting period, Bruce Power is planning to have four of its units offline for refurbishment, some with their

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<sup>42</sup> Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 1.

<sup>43</sup> DBRS Limited (DBRS Morningstar), "Rating Report: Ontario Power Generation Inc.," April 16, 2020, at 3.

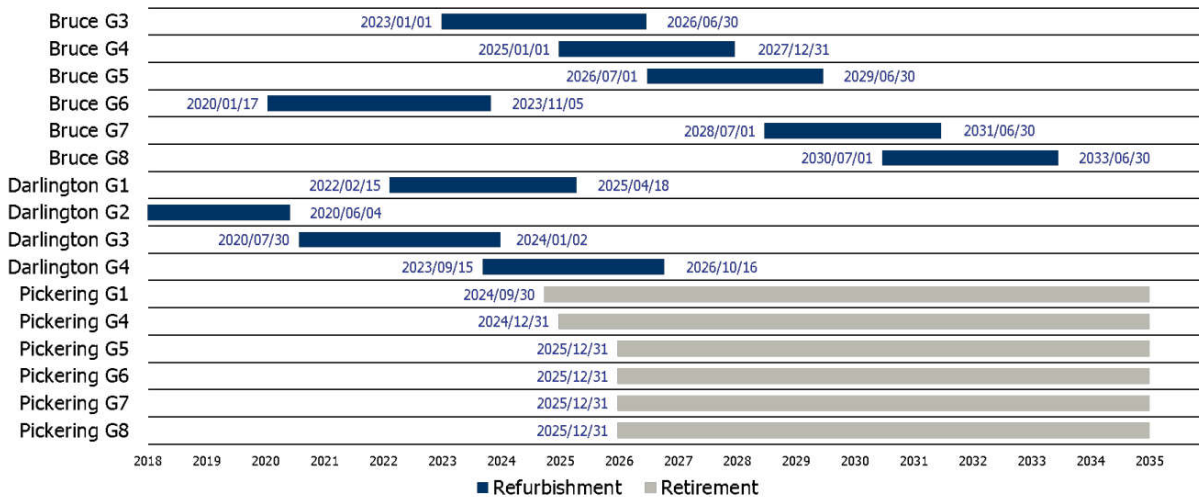
<sup>44</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 104. Clarification added.

<sup>45</sup> S&P Global Ratings, "Research Update: Ontario Power Generation Inc.," July 17, 2020, at 1.



own overlapping outages.<sup>46</sup> These circumstances will place a high demand on the highly skilled resources required to support both projects that rely on certain of the same vendors and key tradespeople. As such, there are inherently higher risks related to project execution during this period of significantly increased sector activity. The schedule of the OPG and Bruce Power projects (along with Pickering retirements) is shown in Figure 7 below.

**Figure 7: Ontario Nuclear Refurbishment and Retirements Schedule<sup>47</sup>**



Second, OPG plans to execute new scope during the refurbishment of Units 3, 1 and 4 in the form of digital turbine controls and generator excitation controls. This scope was excluded from the Unit 2 refurbishment for two main reasons: (1) there was still useful life left in the existing control systems on Unit 2; and (2) to mitigate risk, given that Unit 2 was the first unit to be refurbished and that this large FOAK modification would have introduced additional risk into the planning and execution of the refurbishment. The addition of this scope with which OPG does not yet have experience brings with it increased challenges and risks for the remaining units.

Third, OPG is at increased risk related to the potential for vendor default. The risk of vendor default is already heightened in the context of OPG’s nuclear operations as a result of the small pool of qualified vendors available to perform nuclear engineering and construction. In particular, vendors SNC Lavalin Nuclear Inc. (“SNC”) and Aecon Construction Group Inc. (“Aecon”) represent the most material of OPG’s vendor default risk because of the volume of work they perform for OPG, including acting in a joint-venture (CanAtom) as the main vendor for the DRP. In May 2020, SNC’s credit rating

<sup>46</sup> Bruce Power refers to its nuclear refurbishment program as Major Component Replacement.

<sup>47</sup> Independent Electricity System Operator, 2020 Annual Planning Outlook, at 28.



by S&P was affirmed at “BB+” (with a negative outlook), following a downgrade from “BBB-“ in August 2019. S&P’s outlook on SNC remains “negative” based primarily on uncertainty in the company’s ability to improve earnings and cash flow, especially in context of the COVID-19 pandemic that is resulting in weaker than expected earnings, a weaker economic environment and lower construction activity.<sup>48</sup>

Fourth, the COVID-19 pandemic is an unforeseen ‘black-swan’ event. OPG did not allocate any DRP contingency to the risk of a pandemic outbreak. Concentric understands that OPG continues to seek ways to manage the currently known impacts of the pandemic, including the incremental costs incurred to date. The inherent uncertainty of the pandemic’s evolving course, however, makes it difficult to predict the full range of response actions that may become necessary in the future and any ultimate impact on the DRP cost or schedule. For example, in response to the pandemic and Ontario’s state-of-emergency declaration in mid-March 2020, OPG made the following decisions with respect to the refurbishment schedule: (i) continue to return Unit 2 to service (Unit 2 was safely returned to service on June 4, 2020); and (ii) defer the start dates of the refurbishment outages of Units 3, 1 and 4 by four months each.

In response to the pandemic, OPG conducted a risk review to identify any new or increased risks arising both from the pandemic itself, and also from OPG’s decision to delay the refurbishment start dates of Units 3, 1 and 4. This risk review resulted in new or increased risks being identified, which can be summarized as follows:

1. Productivity risk: risk of decreased productivity as a result of the COVID-19 protocols (such as physical distancing, enhanced cleaning, use of masks, etc.) associated with working during a pandemic.
2. Resource availability risk: risk of resource conflicts and shortages in the form of both human and equipment resources, including managing of staff and equipment as a result of new overlaps with station planned outages, travel restrictions for specialized resources required on the DRP, and risk of loss of critical project resources due to the overall extended schedule (further compounding the significant anticipated demand for resources during the multiple overlapping refurbishments with Bruce Power).

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<sup>48</sup> S&P Global Ratings, Research Update: SNC-Lavalin Group Inc. 'BB+' Ratings Affirmed; Outlook Remains Negative On Slower-Than-Expected Deleveraging, May 2020.



Depending on the course of the COVID-19 pandemic, these factors may have an impact on the ultimate cost and schedule of the DRP.<sup>49</sup>

We note that OPG does continue to employ robust risk mitigation strategies related to the DRP. From the outset, OPG has approached the project strategically and methodically, including performing numerous front-end planning and preparation activities, such as completion of detailed designs and construction of a full-scale model training reactor, and sophisticated contracting strategies. Through the execution of the Unit 2 refurbishment, OPG has been identifying, reviewing and applying a number of lessons learned and strategic improvements in planning the work on subsequent units. However, notwithstanding these practices, significant execution risks associated with the DRP remain as noted above and cannot be fully offset by mitigation strategies.

## **ii. Cost Recovery Protections Available to Nuclear Owners**

As noted in the OEB's decision in EB-2016-0152, provisions of O. Reg. 53/05 provide important protection to OPG, reducing the company's future recovery risk by establishing the overall need for the DRP in the regulatory context and requiring the OEB to authorize recovery of incurred costs (including if the units are not ultimately returned to service), subject to a prudence review. However, Concentric finds that similar risk reducing properties are also or have been present in other jurisdictions that have undergone large-scale nuclear construction projects, including among the proxy companies considered by Concentric in Section 8, and thus are taken into account in this report's recommendations for OPG's equity ratio.

To make this assessment, Concentric compared O. Reg. 53/05 from a risk mitigation perspective to similar legislation and regulatory rules that have enabled nuclear construction in other jurisdictions, focusing on whether: 1) the relevant regulator must approve the need for the new generating plant before construction begins (*i.e.*, the utility does not face the risk of not being subsequently allowed to close the project to rate base upon completion); 2) the utility is allowed to recover prudently-incurred construction and financing costs before the plant goes into service; 3) the utility is allowed to recover costs that exceed the originally approved projections, subject to a prudence review by the regulator; and 4) the utility is able to recover prudently incurred construction costs if the project is abandoned. In particular, Concentric reviewed legislation in the following three jurisdictions where large scale nuclear projects are underway or have been completed (or abandoned): Georgia, South

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<sup>49</sup> Concentric understands that OPG does not intend to seek recovery of any pandemic-related cost impacts through the 2022-2026 rate application but rather will propose to record the impacts in the Capacity Refurbishment Variance Account for the OEB's review at the conclusion of the DRP.



Carolina and Florida. The following is a brief summary of the relevant legislation and statutes in each jurisdiction.

**Figure 8: Summary of Generation Construction Enabling Legislation**

	<b>South Carolina<sup>50</sup></b>	<b>Georgia</b>	<b>Florida</b>
Does commission approve need for new generation before construction begins?	Yes	Yes	Yes
Is utility allowed to recover prudently incurred construction and financing costs before plant goes into service?	Yes	Yes	Yes
Is utility able to recover prudently incurred construction costs if plant is abandoned before completion?	Yes	N/A <sup>51</sup>	Yes

As demonstrated in Figure 8, the legislation and statutes in South Carolina, Georgia and Florida include regulatory protection and assurance of cost recovery for nuclear construction projects comparable to that available to OPG through O. Reg. 53/05. Additionally, all three of the jurisdictions allow recovery of prudently incurred construction and financing costs for the projects prior to the plant going into service (*i.e.*, the utility is allowed to place CWIP in rate base and earn a cash return), a provision not available to OPG under O. Reg. 53/05 and not granted by the OEB.<sup>52</sup> On that basis, Concentric concludes that the regulatory mitigation for the DRP is not unique to OPG, and that construction or refurbishment projects in other jurisdictions may not have been feasible without legislative and regulatory support. Further, because these states offer similar risk protection for nuclear projects, it is reasonable to compare the authorized equity ratios for these operating utilities (*i.e.*, South Carolina Electric and Gas, Georgia Power, and Florida Power and Light) to the deemed equity ratio for OPG. Concentric’s analysis of comparable utilities in Section 8 includes data from two of the three of major developers of nuclear plants in those states.<sup>53</sup>

With regard to whether other North American utilities have been allowed to recover cost overruns on large nuclear projects subject to prudence review, Concentric has identified several instances

<sup>50</sup> The Base Load Review Act in South Carolina was repealed in 2017.

<sup>51</sup> The legislation in Georgia does not appear to address this issue directly.

<sup>52</sup> EB-2010-0008, Decision with Reasons, March 10, 2011, at 78.

<sup>53</sup> The third developer, Dominion Energy (which acquired SCANA in 2019), is excluded from the analysis due to a lower percentage of regulated operations than the screening criteria used by Concentric.



where regulators in Florida, South Carolina and Georgia have approved recovery of such cost overruns. While this provision is not explicitly included in the enabling legislation in these three states, our research demonstrates that there has been implicit support for cost recovery when the need arises. The following is a brief summary of examples in each jurisdiction:

- Florida – Florida Power and Light Company (“FPL”) was allowed to recover costs associated with an Extended Power Uprate project at St. Lucie and Turkey Point following a prudence review, despite cost overruns. In 2011, FPL experienced “cost variances” of more than \$60 million in total in two particular cost categories. The Florida Public Service Commission further indicated that “FPL’s cost estimates have increased each year.” However, despite these cost increases, the Commission approved those costs as prudently incurred.<sup>54</sup>
- South Carolina – In November 2016 (before the Base Load Review Act was repealed), the Public Service Commission of South Carolina approved a settlement agreement in which South Carolina Electric & Gas increased the anticipated cost of constructing two units at the VC Summer Nuclear Station by \$831 million following a prudence review.<sup>55</sup>
- Georgia – The Georgia Public Service Commission issued an order in which it “verifies and approves” Georgia Power’s expenses for Vogtle Units 3 & 4. The order further states “[t]he Commission finds and concludes, based on the evidence presented, that the Vogtle Project remains the most economic option available for supplying the identified capacity need, even taking in to account the sources of speculated cost overruns known at this time.”<sup>56</sup>

Concentric further observes that legislative protections related to nuclear construction projects have not eliminated recovery risk for utilities. Indeed, as noted earlier, recent events in the nuclear construction industry in two of the above jurisdictions, South Carolina and Georgia, have, in fact, increased the investors’ perceived risk over such projects.

In particular, in South Carolina, SCANA started construction of the V.C. Summer Plant under the Base Load Review Act (“BLRA”), which, as discussed below, provided regulatory support for cost recovery of new nuclear facilities during construction. The project experienced construction delays, cost overruns and the bankruptcy of the engineering, procurement and construction contractor (Westinghouse). This led SCANA to ultimately abandon the project in July 2017. SCANA sought recovery of its prudently incurred costs up to that time under the provisions of the BLRA. However, SCANA’s credit rating was downgraded by S&P in September 2017 when the consumer advocate in South Carolina challenged the constitutionality of the BLRA, which was ultimately repealed by the South Carolina legislature, and SCANA was eventually acquired by Dominion Energy in order to avoid

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<sup>54</sup> Florida Public Service Commission, Docket No. 120009-EI, Order No. PSC-12-0650-FOF-EI, issued December 11, 2012, at 68, 73, and 75.

<sup>55</sup> Public Service Commission of South Carolina, Docket No. 2016-223-E, Order No. 2017-118, issued February 28, 2017, at 24.

<sup>56</sup> Georgia Public Service Commission, Docket No. 29849, issued February 26, 2013, at 6.



further financial distress. In addition, Santee Cooper, the co-owner of the V.C. Summer plant, is being considered for sale in order to eliminate \$3.6 billion in future interest payments tied to the nuclear construction program.<sup>57</sup>

In Georgia, Georgia Power undertook the construction of Vogtle plant units 3 and 4 after receiving Georgia Public Service Commission (“Georgia PSC”) approval for the new nuclear facilities under the Georgia Nuclear Energy Financing Act. S&P noted in an August 2020 report that Staff of the Georgia PSC have expressed concern that Georgia Power’s stated schedule for completing construction on the units and bringing those units into service appears to be overly aggressive, although Georgia Power continues to report that construction is on schedule for the two units to be in service by June 2021 and June 2022, respectively.<sup>58</sup> In addition, S&P has expressed concern with whether additional costs will be deemed to have been prudently incurred by the Georgia PSC, or if some portion of those costs might be disallowed.<sup>59</sup> The possibility of disallowance associated with cost overruns related to project execution risks similarly exists for OPG’s DRP under O. Reg. 53/05.

In light of recent “megaproject” experiences such as those in South Carolina and Georgia, the investment community continues to consider the DRP as a major source of risk, even taking into account the O. Reg. 53/05 protections. In fact, other recent regulated nuclear mega-projects in North America have only moved forward with enabling legislation that mitigates risks to the utility, including pre-construction finding of need for the project, ability to recover financing costs during construction, approval of costs in excess of original projections, subject to prudence, and protections in the event the project is abandoned. Absent such legislative and regulatory support, other North American utilities have generally not been willing to undertake nuclear mega-projects.

#### **b. Nuclear Facilities Aging Risks**

The majority of OPG’s nuclear fleet is nearing the end of its current operating life, with the Pickering station set to end commercial operation during the upcoming rate period and Darlington units requiring refurbishment as they reach end of ‘first’ life during the period. Both stations therefore face an inherent risk of experiencing increased effects of aging on their operations and output over the upcoming rate period.

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<sup>57</sup> Meyers, Ellen, “SC agency recommends Dominion Energy, NextEra to reform Santee Cooper,” S&P Global Market Intelligence, February 11, 2020.

<sup>58</sup> S&P Ratings Direct, “Research Update: Southern Company and Subsidiaries Outlooks Remain Negative on Higher Nuclear Construction Costs, Ratings Affirmed,” August 6, 2020.

<sup>59</sup> *Ibid.*



The CANDU reactors at Darlington have limited remaining design life, thus necessitating the DRP to ensure the generating units are fit for service for another 30 years. As the units continue to age toward their end of ‘first’ life, there is a greater risk of emerging equipment issues necessitating incremental repair and maintenance expenditures, as well as generation interruptions.

Additionally, Concentric understands that OPG continues to monitor a fitness-for-service risk for the last two units to be refurbished, Units 1 and 4, whereby their effective full-power hours may potentially expire prior to the planned refurbishment dates, necessitating potential idling of the units. This risk has been marginally increased by the deferral of start dates of the refurbishment outages for the Units 3, 1 and 4 in response to COVID-19 conditions.

Finally, over the last several years, Darlington has experienced variable forced loss rate (“FLR”) levels that may suggest less predictable performance in the pre-refurbishment period, due to equipment issues. The most recent completed year, 2019, resulted in a 4.8% FLR, notably higher than the 2018 year’s 1.1% FLR and OPG’s EB-2016-0152 target of 1%. Similarly, the FLR of 4.9% in 2015 was higher than in 2016 (2.3%) and 2017 (1.7%), as well as OPG’s target.<sup>60</sup>

For Pickering, OPG has announced its intention to optimize the shutdown sequence of four of the station’s units through to the end of 2025, extending their life for one year beyond 2024. OPG has forecast its nuclear generation for the upcoming rate application to reflect that assumption. The extension beyond December 31, 2024, however, requires approval from the CNSC through a public hearing process. In addition to inherent risks associated with the regulatory approval process, for the extension to be achieved, OPG must undertake technical analysis and inspections to validate continued fitness-for-service of the plant’s components. Notably, this extension is the latest in the series implemented by OPG over the last number of years. Given the aging of the plant, the technical and regulatory risks associated with achieving an extension would be expected to increase with each successive instance, as would the ongoing operating cost and generation revenue risks for a station operating closer to its ultimate shutdown date. In fact, no other CANDU plant has operated as long as the planned life of Pickering, which remains the longest operating plant among CANDU peers. On this basis, Concentric believes that the currently planned extended operating period carries increased risk over that of the planned extension at the time of EB-2016-0152.

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<sup>60</sup> 2016 – 2019 Data: EB-2020-0290, Ex. E2-1-2, Table 1; 2015 Data: EB-2016-0152, Ex. E2-1-2 Table 1.



Additionally, there is recent evidence of increased equipment aging issues that are necessitating more frequent unbudgeted planned outages, with three such outages occurring to date in 2020 related to primary heat transport system and other leaks.<sup>61</sup>

Finally, OPG has reduced the FLR target for the upcoming rate period to 3.5%, which is lower than the OPG's EB-2016-0152 target.<sup>62</sup> While Pickering had a FLR performance of 1.6% in 2019, this is notably better than OPG's EB-2016-0152 target of 5% and several prior years of close-to-target performance.

On balance, the older plant, recently increased incidence of aging issues and the more aggressive FLR target relative to EB-2016-0152 lead Concentric to conclude that Pickering is at higher risk for increased expenditures and generation revenue shortfall than at the time of EB-2016-0152.

The above risks were noted by DBRS in their 2020 credit rating report on OPG, stating “[n]uclear generation faces higher operating risks than other types of power generation because of its complex technology (approximately 56% of OPG’s production in 2019). Financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear GS), are greater given the high fixed-cost nature of these plants and since lost revenues resulting from outages are not recoverable through rates.”<sup>63</sup>

In reaching its conclusion on the increased aging risks for the Darlington and Pickering stations, Concentric has considered that, under the EB-2016-0152 Custom IR framework that Concentric understands the company will propose to continue in this rate term, OPG may have the ability to seek regulatory relief from the OEB in the case of a radical change to its nuclear business. For example, the OEB noted in its EB-2016-0152 Decision and Order that “[s]hould the outcome of the technical assessments or system planning decisions significantly impact operation of Pickering in 2021 [the year of planned extension], OPG shall return to the OEB to seek direction.”<sup>64</sup> Such a potential regulatory outcome, however, while putting an upper bound on the potential risk faced by OPG does not negate it, nor does it, by itself, mitigate the incremental risks faced by OPG related to its aging units.

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<sup>61</sup> EB-2020-0290, Ex. E2-1-2, Table 1; Ex. E2-1-1.

<sup>62</sup> EB-2020-0290, Ex. E2-1-2, Table 1

<sup>63</sup> DBRS, “Ontario Power Generation Inc.,” April 16, 2020, at 3.

<sup>64</sup> EB-2016-0152 Decision and Order, December 28, 2017, at 61. Clarification added.



### **c. Pickering Retirement**

For the first time in OPG's history, the rate application will encompass a period of significant reduction in OPG's regulated operations, due to the wind down and shutdown of the Pickering station. The station represents six out of ten of the company's operating nuclear reactors and up to approximately 35% of the company's operating costs, and is served by over 3,000 employees out of the Company's 9,000-plus total workforce. With plans to pursue an extension of Pickering operations for four out of the six operating units through 2025, the planned station shutdown date is at the end of 2025. This introduces a number of unique additional risks and significant challenges that must be taken into account in assessing the risk profile of the regulated business relative to EB-2016-0152. Among others, these risks and challenges include organizational and potential operational disruption, increased forecasting risk and reduced nuclear fleet diversification.

Organizationally, the end of Pickering commercial operations will require OPG to downsize 3,000-plus employees, which will be a complex undertaking. The inevitable disruption that will be caused by the large scale reorganization carries risks to the operational effectiveness and efficiency of the Company's nuclear business through the upcoming rate term.<sup>65</sup>

In addition to the risk of increased operating costs or decreased output associated with the organizational disruption, the upcoming Pickering shutdown creates considerable new forecasting risk for OPG as its nuclear cost-based rates are set on a forward-looking basis. Namely, for at least the years 2025 and 2026, OPG must forecast its operating profile as a very different organization, without the benefit of historical experience. In addition, planning for the immediately preceding years involves making assumptions about organizational changes and strategies to prepare for the shutdown and the post-shutdown operations. For example, OPG's business plan lays out targets of increased cost efficiencies in such areas as technology solutions, organization redesign, work site relocation and others to mitigate, to a large extent, the need to reallocate corporate and operations support costs currently assigned to Pickering to the remaining operations after the Pickering shutdown.

In Concentric's opinion, the business transformation and workforce redeployment brought about by the retirement of Pickering increase the incremental risks that either one of the two initiatives – transformation and redeployment – would carry on its own. Under the current regulatory

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<sup>65</sup> Concentric understands that based on current collective agreement provisions, the hydroelectric business is unlikely to be significantly affected by the downsizing and redeployment exercise.



framework, OPG bears the financial risks associated with forecasting the outcome of its transformation efforts.<sup>66</sup>

In addition, the retirement of Pickering will reduce OPG's diversification among its nuclear fleet, meaning the company's ability to recover nuclear costs will be fully tied to the Darlington output. While Darlington units have historically been more reliable than the Pickering plant, due to Pickering's early age and design, the countervailing risk is that of asset concentration. For example, occurrence of an unanticipated issue at Darlington, including as the last of the units return from refurbishment over 2025 and 2026, could cause large revenue shortfalls for OPG in light of reduced or eliminated Pickering generation. As noted by Moody's, "[OPG's nuclear] segment also benefits from diversification across 2 nuclear generating stations, with 6 and 4 operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking the nuclear refurbishment. The shutdown of the Pickering nuclear generating station in 2024 will reduce diversity and, with fewer operating nuclear units, heighten the impact of any unplanned outages."<sup>67</sup> This risk is related to the generation mix risk, which is discussed in further detail in a subsequent section of the report.

Concentric also notes that OPG anticipates that it will incur a significant amount of severance and workforce transition costs, currently estimated in the order of \$1 billion, related to the Pickering closure. A recent amendment to O. Reg. 53/05 has established a deferral account to record and subsequently recover such costs, subject to the OEB's approval through a prudence review. As Concentric assumes that this mechanism will allow for the substantial full recovery of those costs by OPG, this did not have a material impact on our assessment of OPG's risk profile.

### **3. Climate Risks**

Since EB-2016-0152, the intensifying risk of climate change has been an important source of incremental business risk for the regulated generating industry generally, including OPG's generating assets. Specifically, increased climate risks have been observed through direct impacts to OPG's assets, more pronounced environmental trends, recognition of impacts on the overall electricity system, and recognition of impacts on financial markets and broader economy. The ultimate

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<sup>66</sup> Concentric understands that OPG previously undertook a Business Transformation initiative over the 2011-2015 period, which was a subject of OPG's payment amounts proceeding in EB-2013-0321. However, unlike the upcoming rate application, that initiative was well advanced at the time OPG sought to set rates reflecting its outcome and did not involve a significant redeployment or downsizing, instead relying on attrition-based workforce reductions. It also predominantly focused on support functions rather than core generating station operations.

<sup>67</sup> Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 5. Clarification added.



response to these risks, whether in the form of after-the-fact action or proactively increased resilience, can entail increased expenditures, reduced flexibility and/or reduced output for OPG's regulated businesses in the future.

Some of the developments are summarized below:

- OPG's Calabogie Hydroelectric Generating Station, a five MW regulated facility that OPG had been planning to rebuild, was struck and largely destroyed by a tornado in September 2018.<sup>68</sup>
- OPG has documented risks of maintaining cooling for various plant systems due to warmer Lake Ontario temperatures.<sup>69</sup> For the nuclear stations, primary, secondary and auxiliary systems use lake water to maintain cooling. As lake water temperatures increase in the summer months, the ability to maintain cooling of system components becomes increasingly difficult and may result in lower output through unit derates. Additionally, warmer lake temperatures encourage the growth of aquatic life, thus increasing the risk of algae bloom events as was experienced at Pickering in 2018, forcing four units offline over a span of a number of days.<sup>70</sup>
- The Ottawa River, which hosts a substantial portion of OPG's regulated hydroelectric fleet (four facilities with a total capacity of 912 MW), has seen record floods in recent years.<sup>71</sup> A recent report<sup>72</sup> released by Ottawa predicts more intense precipitation, increased risk of tornadoes and wildfires in the Ottawa area due to climate change.
- Other general environmental trends include increasing air temperature in Canada, which, per Canada's Changing Climate Report has been at approximately twice the global average rate, with extreme warm temperatures becoming hotter.<sup>73</sup> This warming can be expected to contribute to an increased risk of extreme fire weather,<sup>74</sup> which would put utilities such as OPG at a range of risks including disrupted station access/operations, interrupted telecommunications and bottlenecked transmission. These risks have the potential to impact

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<sup>68</sup> OPG.com, "Century-old Calabogie Generating Station set to be rebuilt," July 3, 2019.

<sup>69</sup> OPG, Quarterly Risk Report – Q2 FY2020, August 11, 2020.

<sup>70</sup> Gilligan, Keith, "Is Algae the New Nuisance Neighbor for the Pickering Nuclear Station?" durhamregion.com, August 8, 2018.

<sup>71</sup> The National Capital Commission's Climate Change Adaptation Initiative - National Capital Commission (ncc-ccn.gc.ca).

<sup>72</sup> *Ibid.*

<sup>73</sup> Canada's Changing Climate Report, 2019.

<sup>74</sup> *Ibid.*



station output. Scientists have also expressed high confidence that streamflow regimes will shift and that daily extreme precipitation will increase in Canada.<sup>75</sup>

- Consideration of extreme weather demand has been integrated into the IESO's Reliability Outlook<sup>76</sup> and capacity assessment criteria. Going forward, OPG may be impacted by associated changes in the IESO's outage approval process where extreme weather may potentially restrict OPG's ability to take outages at otherwise optimal times.

Risks influenced by climate change, such as severe weather events, or resulting directly from climate change, such as those due to higher lake temperatures and changing precipitation patterns are, therefore, increasing for OPG. Furthermore, investors, central banks and financial regulators are increasingly recognizing the risk of climate change to the economy, the stability of the financial system, and specific industries and investments. Examples include:

The Bank of Canada has indicated that it views climate change as an emerging risk for the Canadian economy and financial system. Specifically, the Bank of Canada has observed that:

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*Climate change continues to pose risks to both the economy and the financial system. These include physical risks from disruptive weather and events and transition risks from adapting to a lower carbon global economy.<sup>77</sup>*

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The Bank of Canada indicates that it is incorporating climate change risk into its analysis of the Canadian economy and financial system, that climate change creates important physical risks in Canada and globally, and that the move to a low carbon economy involves complex structural adjustments, creating new opportunities as well as transition risk.<sup>78</sup>

In September 2020, the Commodity Futures Trading Commission ("CFTC"), the financial regulator that oversees the trading of futures and options in the U.S., published a report concluding that climate change is a risk to the U.S. financial system.<sup>79</sup> In particular, the CFTC noted the economic risk of changes that are required to mitigate climate change and the disruptive effect those changes might

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<sup>75</sup> Cohen, S., Bush, E., Zhang, X., Gillett, N., Bonsal, B., Derksen, C., Flato, G., Greenan, B., Watson, E (2019): Synthesis of Findings for Canada's Regions; Chapter 8 in Canada's Changing Climate Report, (ed.) E. Bush and D.S. Lemmen; Government of Canada, Ottawa, Ontario, at 424-443.

<sup>76</sup> IESO Reliability Outlook, From April 2019 to September 2020, at 1, 20.

<sup>77</sup> Bank of Canada Financial System Review-2019, May 2019, at 28.

<sup>78</sup> *Ibid.*, at 28-29.

<sup>79</sup> U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System," September 9, 2020.



have on the stability of the financial system itself. The key conclusions of the CFTC report are as follows:<sup>80</sup>

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*Climate change poses a major risk to the stability of the U.S. financial system and to its ability to sustain the American economy. Climate change is already impacting or is anticipated to impact nearly every facet of the economy, including infrastructure, agriculture, residential and commercial property, as well as human health and labor productivity. Over time, if significant action is not taken to check rising global average temperatures, climate change impacts could impair the productive capacity of the economy and undermine its ability to generate employment, income, and opportunity.*

*This reality poses complex risks for the U.S. financial system. Risks include disorderly price adjustments in various asset classes, with possible spillovers into different parts of the financial system, as well as potential disruption of the proper functioning of financial markets. In addition, the process of combating climate change itself—which demands a large-scale transition to a net-zero emissions economy—will pose risks to the financial system if markets and market participants prove unable to adapt to rapid changes in policy, technology, and consumer preferences. Financial system stress, in turn, may further exacerbate disruptions in economic activity, for example, by limiting the availability of credit or reducing access to certain financial products, such as hedging instruments and insurance.*

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S&P has incorporated ESG criteria into its credit rating analysis, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change. For example, in January 2020, investment manager BlackRock sent a letter to its clients announcing a number of initiatives to place sustainability at the center of its investment approach, including: making sustainability integral to portfolio management; exiting investments that present a high sustainability-related risk, and strengthening its commitment to sustainability and transparency in investment stewardship activities.<sup>81</sup>

McKinsey and Company published a report in April 2019 in which the consulting firm makes specific recommendations to the utility industry with regard to managing climate change risk. While noting that severe weather events such as hurricanes and wildfires are getting worse, McKinsey writes: “In other ways, too, utilities are more vulnerable to extreme weather events than in the past.”<sup>82</sup> The report goes on to observe: “Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage

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<sup>80</sup> *Ibid.*, at i and ii.

<sup>81</sup> BlackRock Letter to CEOs, “A Fundamental Reshaping of Finance,” January 20, 2020.

<sup>82</sup> McKinsey and Company, “Why, and how, utilities should start to manage climate change risk,” April 2019, at 3.



and upgrading infrastructure after the fact is expensive and traumatic.”<sup>83</sup> McKinsey also quotes from a 2018 report by the National Climate Assessment which stated that “utilities could see negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence of storms. This will increase the financial cost to utilities of climate change and increase the benefits of being prepared.”<sup>84</sup>

In summary, the risks associated with changing climate parameters and severe weather events have increased for OPG since EB-2016-0152, at the asset, industry, electricity system and macroeconomic levels. Investors are keenly focused on how such risks are being managed by organizations. While we expect that the risks will continue to manifest over time, current trends point to a greater and potentially more urgent likelihood of incremental expenditures and operational impacts over the upcoming rate setting period. Unless they also happen to increase the output, refurbish or add operating capacity to a regulated facility, such incremental expenditures would not be subject to existing protections under O. Reg. 53/05 or other deferral or variance accounts currently in place for OPG.

#### **4. Generation Asset Mix**

The OEB has consistently recognized that nuclear generation assets are a higher risk than hydroelectric generation assets. For example, in support of its findings in EB-2013-0321 that OPG’s business risk had changed between EB-2010-0008 and EB-2013-0321, the OEB cited the “increase [in the] proportionate share of rate base related to hydroelectric facilities from about half to approximately two-thirds now [*i.e.*, as of EB-2013-0321],” while noting that the “relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings.”<sup>85</sup> The OEB similarly stated in EB-2016-0152 that “[t]he OEB accepts the opinions of both experts that, in general, there are more business risks associated with nuclear generation than with hydroelectric.”<sup>86</sup>

The OEB further clarified its view in EB-2016-0152 that it was not only rate base that drove the risk profile of OPG, but also the relative contributions of nuclear and hydroelectric generation. Specifically, the OEB found, “while the nuclear rate base will increase substantially over the five-year term, the MWh generated by nuclear will not increase, and in fact will decrease at times as units are taken out of service at Darlington. The relative contributions of revenue from hydroelectric and

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<sup>83</sup> *Ibid.*

<sup>84</sup> *Ibid.*, at 4.

<sup>85</sup> EB-2013-0321, Decision with Reasons, November 20, 2014, at 113. Clarification added.

<sup>86</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 102.



nuclear will not change in favour of nuclear, so it is not axiomatic that the equity thickness should be increased on this basis.”<sup>87</sup>

With the expansion of OPG’s regulated nuclear investment over the upcoming rate term due to the \$12.8 billion DRP, the nuclear generation business is projected to comprise a comparatively larger portion of OPG’s overall regulated rate base. In Concentric’s opinion, this increase in nuclear rate base alone, with its attendant risk, continues to be supportive of a need for an increased equity thickness, notwithstanding that there is no relative increase in the nuclear versus hydroelectric MWh. In reaching this conclusion, Concentric carefully considered the OEB’s prior findings that recognized both rate base and generation output as relevant to assessing the impact of relative proportions of nuclear and hydroelectric business on OPG’s overall risk profile. In recognition of these findings, we also discuss below how the decline in nuclear generation will create *additional* risk, more than offsetting any reduction in risk that can be attributed to the relative decline in overall nuclear revenue after the Pickering shutdown.<sup>88</sup>

First, while MWh generated is one indicator of the relative proportions of OPG’s business comprised of nuclear versus hydroelectric generation, it is ultimately the investment in plant, not the output itself, that drives the need for capital. For example, if a utility were to invest in low capacity factor peaking facilities to meet periods of high demand, measuring the operating risk related to those facilities based on their output would significantly understate their associated risk. Based on its experience, Concentric does not believe that investors and rating agencies will reduce their risk view of OPG when it is seeking investment to support a nuclear capital program because of a reduction in the nuclear generation output. In fact, as noted earlier, at least one rating agency, Moody’s, has stated that OPG’s risk will in fact increase due to lower diversification of its nuclear portfolio after Pickering shutdown.<sup>89</sup>

Second, it is the precise sources of OPG’s increased risk (*i.e.*, the DRP and the retirement of Pickering) that are leading to decreased levels of nuclear generation over the upcoming rate period. In other words, nuclear risk is rising while nuclear generation is decreasing (and rate base is increasing).

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<sup>87</sup> *Ibid.*

<sup>88</sup> In its Decision and Order in EB-2016-0152, at 101, the Board stated that “[t]he EB-2013-0321 decision deals with more than one aspect of the impact of the increase in the hydroelectric generation portfolio. The two factors were the increase in annual MWh generated by hydroelectric with the addition of 48 previously unregulated facilities to the regulated portfolio and the completion of the Niagara Tunnel, and the increase in hydroelectric rate base by the addition of these assets to the regulated portfolio.”

<sup>89</sup> Moody’s Investors Service, “Ontario Power Generation Inc.,” December 21, 2020, at 5.



Third, the decline in nuclear generation and therefore the ratio of nuclear to hydroelectric generation creates *additional* risk from a cost recovery perspective over the upcoming period. This is because each unit of nuclear generation output will become more financially valuable to OPG as the nuclear generation that recovers the nuclear revenue requirement (including the increased nuclear rate base) is reduced, while continuing to be more financially valuable than each unit of hydroelectric generation. The greater relative cost recovery associated with each unit of nuclear output will put OPG at greater risk related to its nuclear generation operations, both relative to EB-2016-0152 and to its hydroelectric generation.

The increasing value of each unit of nuclear output (on an absolute basis and in relation to each unit of hydroelectric output), is demonstrated in Figure 9 below.

**Figure 9: Value of Nuclear and Hydroelectric Output**

	Value of TWh of Output (\$millions)	
	Nuclear	Hydroelectric
EB-2016-0152 Rate Term	\$82	\$43
2022-2026 Rate Term	\$108	\$44
As of 2026	\$121	\$44

As shown in the Figure 9 above, each nuclear TWh had a value of approximately \$80 million during the EB-2016-0152 rate term, compared to approximately \$43 million for a hydroelectric TWh.<sup>90</sup> Over 2022 to 2026, based on OPG’s draft rate filing at the time of writing, the value of a nuclear TWh has increased to approximately \$108 million, compared to approximately \$44 million for a hydroelectric TWh.<sup>91</sup> This represents an approximately 32% increase in the value of each unit of nuclear output and an approximately 64% increase in the amount by which the nuclear unit of output is more valuable than the hydroelectric unit of output. By 2026, the financial value of a nuclear TWh increases further, to approximately \$121 million, or approximately 48% higher than in EB-2016-0152 and an approximately 97% increase in the amount by which the nuclear MWh is more valuable than the hydroelectric MWh. To put those figures into further perspective, foregone revenues from a hypothetical seven-day outage at one of OPG’s Darlington nuclear reactors would have been

<sup>90</sup> For nuclear, based on EB-2016-0152 approved smoothed base payment amounts, arithmetically averaged over 2017 to 2021. For hydroelectric, based on approved base payment amounts pursuant to the IRM formula in EB-2016-0152 and subsequent annual proceedings, arithmetically averaged over 2017 to 2021.

<sup>91</sup> For nuclear, based on draft proposed smoothed base payment amounts, arithmetically averaged over 2022 to 2026. For hydroelectric, based on the approved 2021 base payment amount that will be held constant over the period pursuant to O. Reg. 53/05.



approximately \$12 million during the EB-2016-0152 period, rising to \$15 million in the upcoming rate setting period, and ending at approximately \$17 million in 2026. This risk will be even more pronounced for OPG when Pickering retires, as an outage at one of OPG's remaining reactors would result in a loss of a quarter of OPG's nuclear generating capacity.

To further illustrate our analysis with respect to relative rate base and per unit-of-output cost recovery value, the following information is provided below:

- Figure 10 provides the relative nuclear and hydroelectric rate base from the start of OPG rate regulation by the OEB through to the upcoming rate period, as well as OPG's common equity ratio, as approved for the historical period and the minimum proposed ratio in this report for the upcoming rate term.
- Figure 11 shows a combination of the actual and forecast generation for the prescribed nuclear and hydroelectric facilities over the EB-2016-0152 rate term and the 2022-2026 forecast period
- Figure 12 is a graphical representation of the changes in generation and rate base mix over time. Figure 12 shows that nuclear generation decreases over the upcoming rate period while hydroelectric generation stays relatively flat. Meanwhile, nuclear rate base increases over the rate period, which, when combined with decreasing output, increases the value to OPG of each unit output, for which it is at risk.
- Figure 13 demonstrates this outcome, providing the unit prices for nuclear and hydroelectric generation output and the relationship between the two. Figure 13 shows that the unit price of each MWh of nuclear output increases significantly over the upcoming rate period while that for hydroelectric output is fixed.

As can be seen from Figure 10, the portion of OPG's total rate base that is nuclear was at its lowest (*i.e.*, 23%) during the period for which rates in EB-2013-0321 were set, which was also the period for which the OEB lowered OPG's common equity ratio to 45%. However, starting in 2017, the nuclear portion of rate base began to increase significantly. By 2026, *i.e.*, the end of the proposed five-year rate period, the nuclear portion of rate base is expected to be at an all-time high.



**Figure 10: OPG's Prescribed Facilities Rate Base (\$ billions)**

	EB-2007-0905 Payment Order		EB-2010-0008 Payment Order		EB-2013-0321 Payment Order		EB-2016-0152 Rate Period <sup>92</sup>					EB-2020-0290 Rate Period				
	2008	2009	2011	2012	2014	2015	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
<b>Hydro</b>	\$3.9	\$3.8	\$3.8	\$3.7	\$7.5	\$7.5	\$7.5	\$7.5	\$7.5	\$7.6	\$7.7	\$7.8	\$8.0	\$8.2	\$8.5	\$8.9
<b>Nuclear</b>	\$2.5	\$2.3	\$2.4	\$2.3	\$2.3	\$2.3	\$2.9	\$3.0	\$3.0	\$7.1	\$7.5	\$8.8	\$8.8	\$11.3	\$12.5	\$13.4
<b>Nuclear Portion of Rate Base</b>	39%	38%	39%	38%	23%	23%	28%	29%	29%	48%	49%	53%	52%	58%	60%	60%
<b>Rate Term Ratio Avg</b>	38%				23%		38%					57%				
<b>Common Equity Ratio</b>	47%	47%	47%	47%	45%	45%	45%	45%	45%	45%	45%	50% <sup>93</sup>	50%	50%	50%	50%

<sup>92</sup> Hydroelectric values as stated in EB-2016-0152, Ex. L, Tab 3.1, Schedule 20 VECC-005, Table 5; nuclear values as stated in EB-2016-0152 Payment Amounts Order, Appendix A, Tables 1-5.

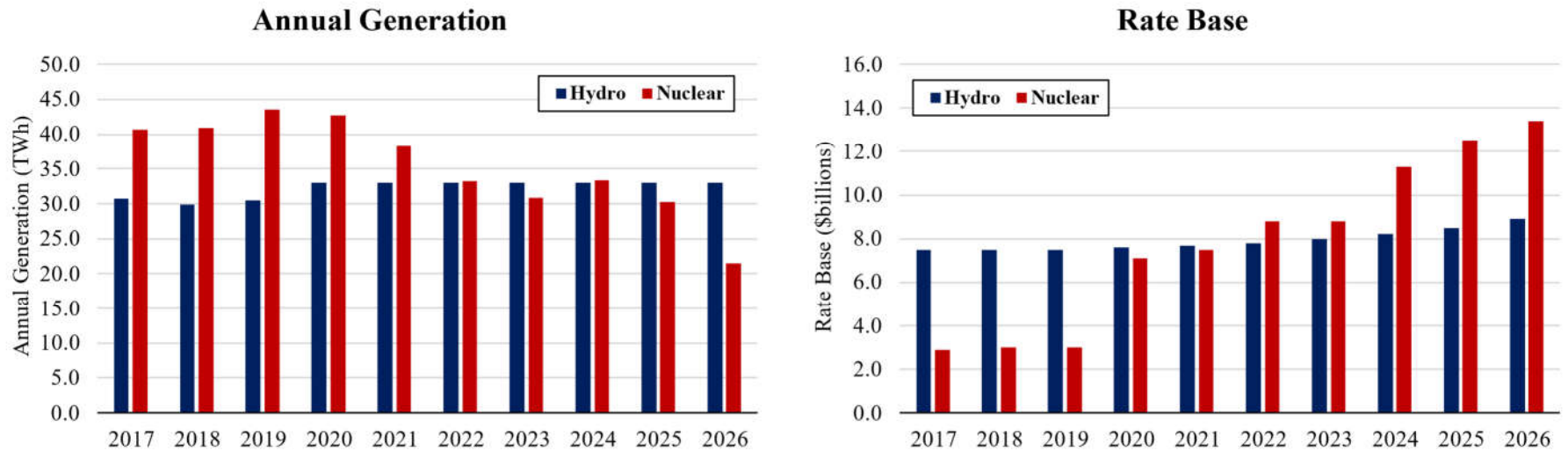
<sup>93</sup> Proposed minimum equity ratio for 2022-2026 rate-setting period.



**Figure 11: OPG’s Prescribed Facilities Generation (TWh)**

	EB-2016-0152 Rate Period					EB-2020-0297 Rate Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
<b>Hydro</b> <sup>94</sup>	30.7	29.9	30.5	33.0	33.0	33.0	33.0	33.0	33.0	33.0
<b>Nuclear</b>	40.7	40.9	43.5	42.7	38.3	33.2	30.8	33.3	30.2	21.5

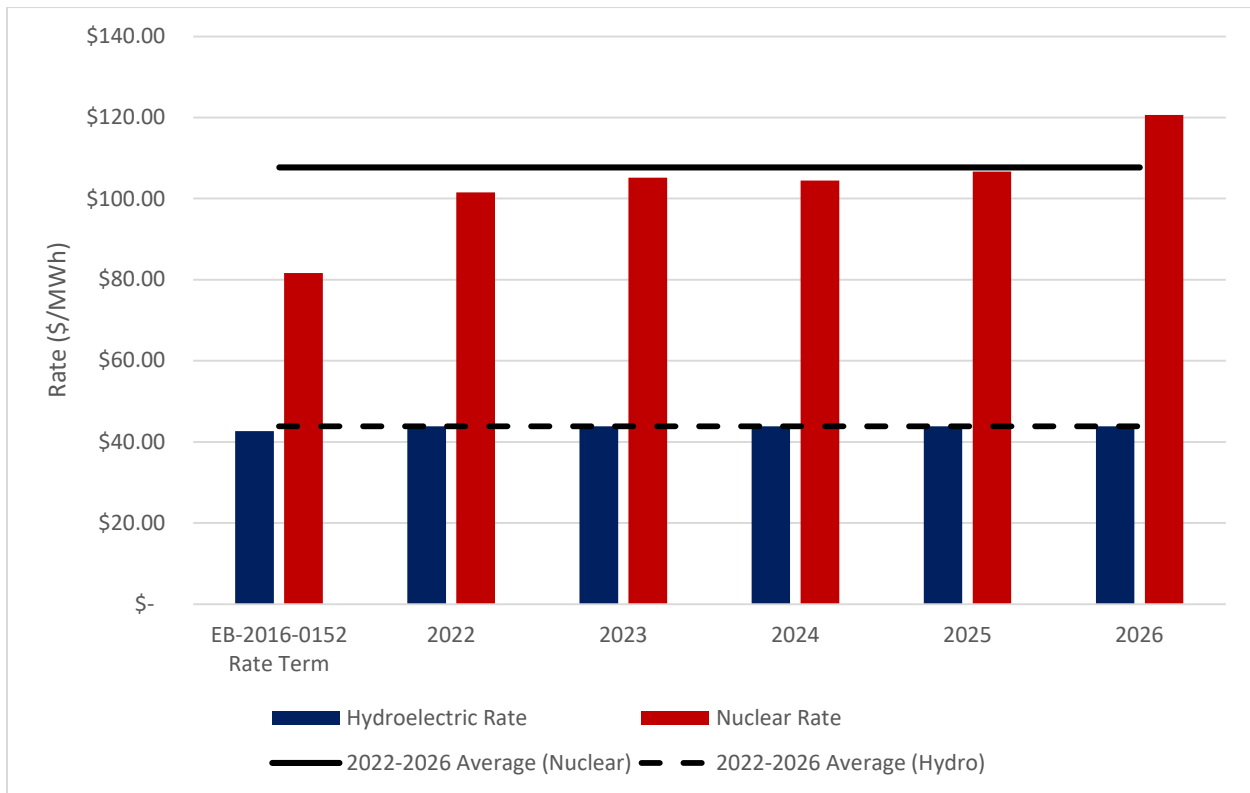
**Figure 12: OPG’s Generation and Rate Base Over Time, by Fuel Source**



<sup>94</sup> Regulated Hydroelectric production for 2020 - 2026 is the 2014 and 2015 average OEB approved hydroelectric production per EB-2013-0321 Decision and Order, at 9, and EB-2016-0152 PAO, App. I, Table 2, line 3.



**Figure 13: Comparative Value of Nuclear vs. Hydroelectric Output**



Concentric has considered the value-of-MWh analysis above in the context of the overall level of revenue requirement to be recovered by each of the generation businesses. This approach recognizes the OEB’s prior findings, including that, in the presence of changing “relative contributions of revenue from hydroelectric and nuclear,” the increase in relative rate base alone “is not axiomatic that the equity thickness should be increased on this basis.”<sup>95</sup> For example, in a scenario where the price per MWh is significantly higher for one technology but the overall revenue requirement to be recovered for that technology represents a small portion of the total regulated revenue, the overall risk profile is unlikely to be significantly impacted. In OPG’s circumstances, however, the estimated nuclear revenue requirement for the upcoming rate period remains at levels substantially similar and in fact higher, due to the DRP, than in EB-2016-0152, until the Pickering retirement at the end of 2025.

While the nuclear revenue requirement does decline in 2026, due to the elimination of Pickering operating costs, it continues to account for 65% of total regulated revenues, in addition to reflecting a significantly higher rate base than the hydroelectric business. It is Concentric’s view that these factors, when combined with the increased diversification risk for the nuclear fleet discussed above

<sup>95</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 102.



and the higher relative value of each nuclear unit of output, result in additional risk that is at least equal to, if not greater than, the notional reduction in risk that can be attributed to the relatively lower overall nuclear revenue requirement by 2026.

In conclusion, by the end of the upcoming rate period, nuclear rate base is projected to be 60% of OPG's total prescribed generation rate base, as compared to 49% at the end of the EB-2016-0152 rate period (and less than 40% during the period in which OPG's deemed equity ratio was 47%). As it is the level of investment that drives the need for capital, given that nuclear business is higher risk, this factor supports the need for a higher equity ratio for OPG. In the context of the OEB's prior findings on the relative output and revenue contributions of each regulated business, Concentric also finds that the increased relative cost recovery risk for each unit of nuclear output versus hydroelectric, \$39 per MWh average difference in EB-2016-0152 to \$77 per MWh difference by the end of upcoming rate period, is a source of additional risk relative to EB-2016-0152. This, coupled with the increase in nuclear-specific business risks discussed earlier, including lower diversification of the nuclear fleet, indicates a substantial increase in OPG's overall business risk for its regulated operations.

### **Changes in Financial Risk**

Financial risk is an important component of a company's overall risk profile. Financial risk, which is focused on solvency and liquidity, is often measured through credit metrics, and a utility's credit rating provides a widely-accepted opinion from a third party credit rating agency of the utility's overall creditworthiness. Concentric's consideration of OPG's financial risk therefore focused on the review of the company's credit rating.

In adopting this approach, Concentric was mindful of the OEB's findings in EB-2016-0152 that "credit risk is not an independent factor in assessing whether business risk has changed – it is the credit rating agencies' assessment of those risks as to how they may affect solvency and liquidity."<sup>96</sup> Concentric agrees that financial risk and business risk are often interrelated. However, Concentric is also guided by the OEB's previous findings distinguishing between financial risk and business risk, in the context of their relationship with capital structure, and specifically that "capital structure should be reviewed only when there is a significant change in *financial*, business or corporate fundamentals."<sup>97</sup> Additionally, Concentric is guided by the fact that, as discussed in the "Background on Prior OEB Decisions" (Section 3 of this report), maintenance of financial integrity is a key component of the fair return standard.

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<sup>96</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 107.

<sup>97</sup> EB-2009-0084, Report of the Board, December 11, 2009, at 49. Emphasis added.



OPG's issuer rating from S&P remains at BBB+ and its stand-alone credit profile absent support from the Province is a bb+ rating (a non-investment grade level), both of which are the same as at the time of EB-2016-0152. Since 2019, OPG also has a Moody's issuer rating of A3, with a stand-alone profile of baa3 (the lowest investment grade rating level) absent support from the Province. With the majority of peer companies being assessed at the a- and bbb+ level on a stand-alone basis (as discussed in Section 8), OPG's stand-alone credit profile under both the S&P and Moody's frameworks suggests that its stand-alone business and financial risks are higher in comparison to peers.

Both S&P and Moody's expect OPG to maintain credit metrics at a certain level in order to maintain its current credit rating. For S&P, the Funds from Operations ("FFO")/Debt ratio is the key metric referred to in S&P's reports on OPG. According to S&P's most recent credit report on OPG, S&P has indicated a downside threshold for the current rating of 13%.<sup>98</sup> Moody's has indicated that its financial metrics assessment could lead to a downgrade if a decline of Cash From Operations pre-Working Capital (CFO)/ Debt ratio to below the 12% threshold on a sustained basis.<sup>99</sup>

These core ratios are expected to be under pressure during the earlier years of the upcoming rate period and OPG's business plan forecasts one or both of them will temporarily decline below the corresponding thresholds. Our understanding is that lower nuclear generation during the DRP, which is expected to impact the rate smoothing determinations and therefore OPG's future operating cash flows, coupled with a heightened capital investment program, including the DRP, contribute to this pressure.

While OPG's business plan indicates that it will continue to focus on communicating to the rating agencies the short-term nature of the potential decline in the metrics and that this decline is not reflective of OPG's ongoing financial strength, there remains an inherent risk of a credit rating action, which would result in a downgrade or a change in credit outlook.<sup>100</sup> In these circumstances and pending the outcome of the upcoming rate application proceeding, Concentric considers the pressure on the credit metrics to signify additional financial risk since EB-2016-0152. An increase in OPG's equity ratio, therefore, and particularly during this period, would be consistent with OPG's increased financial risk and the financial integrity component of the fair return standard.

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<sup>98</sup> In its July 2020 report, S&P stated "[w]e could take a negative rating action on OPG over the next 12-18 months if the company's financial measures weaken, reflecting FFO to debt consistently below 13%." S&P Global Ratings, "Research Update: Ontario Power Generation Inc.," July 17, 2020, at 3.

<sup>99</sup> Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 3.

<sup>100</sup> The credit rating action risk discussed is in addition to the impact of any rating change for the Province that would be expected to affect OPG's rating in a corresponding manner, as was the case in 2015.



## SECTION 8: PROXY GROUP COMPARATIVE ANALYSIS

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### 1. Overview

In addition to assessing changes to OPG’s business and financial risk profile since EB-2016-0152, Concentric also analyzed the equity ratios of other North American utilities screened for risk characteristics similar to OPG’s. To identify companies with risk characteristics similar to OPG, Concentric selected publicly-traded investor-owned utility companies that passed a series of screening criteria based on OPG’s operational profile. Concentric reviewed three separate measures of the equity ratios of those similarly-situated regulated utilities: (1) the historical equity ratios maintained by comparable publicly-traded holding companies; (2) the historical equity ratios maintained by the operating subsidiaries of those holding companies; and (3) the equity ratios authorized by the regulators of those operating subsidiaries. Those measures provide context for where, within a reasonable range, OPG’s equity ratio should be set by the OEB, with the regulated operating company equity ratios being most relevant for purposes of assessing OPG’s regulated equity thickness. Concentric also analyzed two different proxy groups. The first proxy group (the “Concentric Proxy Group”) was a broader group of companies that met the screening criteria described herein. The second proxy group (the “Moody’s Peer Group”) included the companies identified as OPG’s peers by Moody’s.<sup>101</sup> The results for those two proxy groups are provided in the Figure 14 and Figure 15 below.

**Figure 14: Summary of Comparative Analysis Results (Concentric Proxy Group)**

<b>Analytical Approach</b>	<b>Mean Equity Ratio</b>	<b>Median Equity Ratio</b>
Holding Company Equity Ratios: 5-Year Avg.	45.7%	47.4%
Operating Company Equity Ratios: 5-Year Avg.	52.8%	53.0%
Operating Company Equity Ratios: Authorized	49.5%	49.6%

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<sup>101</sup> Moody’s Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.



**Figure 15: Summary of Comparative Analysis Results (Moody's Peer Group)**

<b>Analytical Approach</b>	<b>Mean Equity Ratio</b>	<b>Median Equity Ratio</b>
Holding Company Equity Ratios: 5-Year Avg.	50.6%	49.1%
Operating Company Equity Ratios: 5-Year Avg.	55.9%	53.6%
Operating Company Equity Ratios: Authorized	50.7%	50.1%

Our analysis of comparable regulated utilities with significant regulated generation assets indicates that OPG's current deemed equity thickness is low relative to comparable companies, despite OPG falling towards the upper end of the spectrum of risk profiles established by the proxy companies. Taken together, the analyses support an equity ratio of no less than 50% for OPG.

## **2. Use of Proxy Company Analysis for Cost of Capital Determinations**

Analyses of comparable, or "proxy," companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities and for benchmarking business and financial risks. Proxy groups are used for the following main reasons in cost of capital determinations: (1) adherence to the comparable investment standard; (2) since the cost of capital is a market-based concept, and given that OPG is not a publicly-traded entity, it is necessary to establish a group of companies that is both publicly-traded and comparable to OPG in certain fundamental business and financial respects to serve as its "proxy" for purposes of the cost of capital evaluation process; and (3) even if OPG's regulated operations were held by a stand-alone publicly-traded entity, it is possible that transitory events could bias its market-determined cost of capital in one way or another over a given period of time. A significant benefit of using a proxy group is its ability to mitigate the effects of anomalous events that may be associated with any one company.

Regulatory commissions and cost of capital analysts generally apply a set of screening criteria in order to define a risk-appropriate group of comparable companies. For instance, the Federal Energy Regulatory Commission ("FERC") provides the following summary of its practice for selection of a proxy group for electric transmission companies:

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*Composition of the Proxy Group: In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut*



*during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.<sup>102</sup>*

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While the individual screens require modification based on the subject company to which proxy companies are being compared,<sup>103</sup> the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence that the analyst (or regulator) can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of North American electric utility companies that are risk appropriate for comparison to OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of that range. That determination must be based on an assessment of OPG-specific risks relative to the proxy group and informed judgment. For example, the National Energy Board (predecessor to the Canada Energy Regulator), in discussing the cost of capital for the TransCanada Mainline, stated, “[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences.”<sup>104</sup> In other words, whereas a subject company of average risk relative to the proxy group potentially would warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk potentially would warrant an equity ratio above the mean or median result, and a company of lower risk potentially would warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is a common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG’s capital structure. In the discussion that follows, we present Concentric’s analysis of OPG’s level of business and

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<sup>102</sup> Opinion No. 531, Order on Initial Decision, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45

<sup>103</sup> For instance, the FERC applies a screen for the inclusion of master limited partnerships (“MLPs”) in natural gas pipeline proxy groups that the MLPs derive at least 50% of operating income from, or have 50% of their assets devoted to, interstate operations (see, Opinion No. 510, Portland Natural Gas Transmission System, 134 FERC ¶ 61,129 (February 17, 2011), at 62.

<sup>104</sup> National Energy Board RH-003-2011 Reasons for Decision, TransCanada PipeLines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., March 2013, at 165.



financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB.

### 3. Selection of Proxy Companies

As discussed above, Concentric studied data derived from two separate proxy groups, the Concentric Proxy Group and the Moody's Peer Group.

As a starting point for our screening process for the Concentric Proxy Group, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Algonquin Power & Utilities Corp ("Algonquin"), Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TC Energy Corporation, and the 37 U.S. companies that Value Line classifies as "Electric Utilities."<sup>105</sup>

From that group, Concentric screened for companies that:

- **Own regulated generation assets that are included in rate base.** As it relates to the rate setting process, OPG's assets represent 100% rate-regulated generation. As such, it is important to exclude companies from the proxy group that bear no risks related to regulated generation. The reason for this is the generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its 2017 ratings methodology for regulated electric and gas utilities, "[g]eneration utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;"

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<sup>105</sup> Precedent for the consideration of U.S. proxy companies in Canadian cost of equity analyses is discussed in Appendix C.

<sup>106</sup> Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 21.



- **Own regulated nuclear and/or hydroelectric generation.**<sup>107</sup> As noted earlier, OPG's rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as previously noted, the OEB has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities;
- **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company.** This screen, in combination with the screen below regarding electricity revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated electric operations. While rates in this proceeding are being set for OPG's 100% rate-regulated nuclear operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their revenues and net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, in Concentric's experience, using a screening criteria of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group
- **Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations.** Including only those companies that derive more than 80% of their regulated revenue and net income from regulated electricity operations ensures that the proxy companies, like OPG, derive the predominant share of their financial results from regulated electricity segments. Similar to the regulated revenue and net income screen, the 80% regulated electric revenue and net income screen is not a "bright line," but rather is intended to balance the comparability of the proxy group with its overall size; and

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<sup>107</sup> Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation.



- **Have an investment grade credit rating similar to that of OPG.** As noted earlier, OPG has an “A (low)” issuer and unsecured debt rating from DBRS, a “BBB+” corporate and unsecured debt credit rating from S&P, and an “A3” senior unsecured debt rating from Moody’s. As also noted earlier, S&P and Moody’s rate OPG as “BB+” and “baa3” (*i.e.*, three notches below its corporate credit rating) on a stand-alone basis, before consideration of support by the Province. As credit ratings are based on the utility’s business risk profile (including an assessment of its regulatory environment) and financial risk profile, companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that “it is reasonable to use the proxy companies’ corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk.”<sup>108</sup> Concentric’s credit rating screen selects electric utility companies with investment-grade credit ratings (an S&P credit rating of BBB- or above or a Moody’s credit rating of Baa3 and above), which reduces the need to adjust the results to account for any perceived differences in business or financial risk compared to OPG. Further, selecting proxy companies that, like OPG, have an investment grade credit rating ensures that the proxy companies are generally in sound financial condition. Because credit ratings consider business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.<sup>109</sup>

#### 4. Proxy Group Summary

None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.<sup>110</sup> Fortis only failed the screens that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company’s regulated operations and that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.<sup>111</sup> Algonquin failed the screens that each utility should own more than a minimal amount of regulated nuclear and/or

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<sup>108</sup> See, for example, Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.

<sup>109</sup> The only utility removed from the proxy group due to this screening criterion is PG&E Corporation, which has a sub-investment grade credit rating due to its recent bankruptcy.

<sup>110</sup> Specifically, Emera currently owns no regulated hydroelectric or nuclear generation.

<sup>111</sup> Fortis has 76% regulated electricity revenue and regulated net income, while only owning a minimal amount of regulated hydroelectric generation (and no nuclear generation).



hydroelectric generation and that each utility should derive greater than 80% of consolidated regulated revenue from regulated electricity operations.<sup>112</sup>

In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera, Fortis, and Algonquin in the proxy group, as they otherwise meet our screening criteria. Figure 16 presents the sixteen U.S. companies that met our screening criteria, along with OPG and the three Canadian companies noted above. In addition to the company name, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each company. Exhibit 1 details how each proxy company meets the screening criteria above.

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<sup>112</sup> Algonquin owns just 16 MW of hydroelectric generation according to S&P Global Market Intelligence and has 49% regulated electricity revenue.



**Figure 16: Concentric Proxy Group and OPG**

Company	Ticker	S&P Summary: Credit Rating / Outlook	S&P Summary: Business Risk	S&P Summary: Financial risk
OPG	n/a	BBB+/Stable	Strong	Significant
ALLETE, Inc.	ALE	BBB/Stable	Strong	Significant
Ameren Corporation	AEE	BBB+/Stable	Excellent	Significant
American Electric Power Co., Inc.	AEP	A-/Stable	Excellent	Significant
Avista Corporation	AVA	BBB/Stable	Strong	Significant
Duke Energy Corporation	DUK	A-/Stable	Excellent	Significant
Edison International	EIX	BBB/Negative	Strong	Significant
El Paso Electric Company <sup>113</sup>	EE	Not Rated	Not Rated	Not Rated
Entergy Corporation	ETR	BBB+/Stable	Strong	Significant
FirstEnergy Corporation	FE	BBB/Negative	Excellent	Aggressive
Evergy, Inc.	EVRG	A-/Stable	Excellent	Significant
IDACORP, Inc.	IDA	BBB/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Pinnacle West Capital Corporation	PNW	A-/Stable	Excellent	Significant
PNM Resources, Inc.	PNM	BBB/Stable	Strong	Significant
Portland General Electric Company	POR	BBB+/Negative	Excellent	Significant
Southern Company	SO	A-/Negative	Excellent	Significant
Xcel Energy, Inc.	XEL	A-/Stable	Excellent	Significant
Algonquin Power & Utilities Corp	AQN	BBB/Stable	Strong	Significant
Emera, Inc.	EMA	BBB/Stable	Excellent	Aggressive
Fortis Inc.	FTS	A-/Negative	Excellent	Significant

As described above, Concentric also considered the Moody's Peer Group, which is a proxy group composed of companies identified by Moody's as OPG's peers.<sup>114</sup> Figure 17 presents those three companies along with OPG. Again, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each Moody's peer.

<sup>113</sup> S&P withdrew its ratings on El Paso Electric Co. ("El Paso") on September 18, 2020, due to a lack of sufficient information. Previously, El Paso was rated BBB with a negative outlook, with "Strong" business risk and "Significant" financial risk.

<sup>114</sup> Moody's Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.



**Figure 17: Moody’s Proxy Group and OPG**

<b>Company</b>	<b>Ticker</b>	<b>S&amp;P Summary: Credit Rating / Outlook</b>	<b>S&amp;P Summary: Business Risk</b>	<b>S&amp;P Summary: Financial risk</b>
OPG	n/a	BBB+/Stable	Strong	Significant
Public Service Enterprise Group, Inc	PEG	BBB+/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Exelon Corporation	EXC	BBB+/Negative	Strong	Significant

## 5. Proxy Group Business Risk Analysis

In order to further evaluate the comparability of the proxy group companies, Concentric examined the business risks of each operating company relative to those of OPG. The purpose of this evaluation was to determine the extent to which the companies in the proxy group have similar risk profiles to OPG (indicating that OPG is of average risk, compared to the proxy group), or are more or less risky than OPG (indicating a need to potentially establish a proxy-based capital structure for OPG that is above or below the mean and median of the group).

Concentric focused on two primary business risk characteristics – operational profile, and generation percentage and mix.

### a. Operational profile

Concentric examined the operations of each of the companies in the two proxy groups. Exhibits 5.1 and 5.2 provide summaries of several relevant indicators for the operating subsidiaries of the Concentric Proxy Group and the Moody’s Peer Group, respectively, including: (1) the province or state in which the utility provides service; (2) the ratemaking mechanisms available to the utility (*e.g.*, fuel cost recovery, revenue decoupling, capital cost recovery, etc.); and (3) whether the jurisdiction relies on historical or forecast test years for ratemaking purposes.

In reviewing the comparability of the ratemaking mechanisms available to proxy group companies, Concentric specifically considered the OEB’s statement in EB-2016-0152 that “in OPG’s specific circumstances, there are a number of factors that substantially mitigate that risk [*i.e.*, higher business risks associated with nuclear generation]. These include the various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG the opportunity to recover substantially all their unexpected or unforeseen costs.”<sup>115</sup>

<sup>115</sup> EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.



Based on a review of OPG variance and deferral account activity since the beginning of the current rate term, identified below are the main accounts applicable to OPG's regulated nuclear business.<sup>116</sup> Also provided is Concentric's consideration of the risk-reducing properties, if any, of the accounts, including in the context of the proxy group.

- *Nuclear Liability Deferral Account* (per O. Reg. 53/05) – allows OPG to recover actual revenue requirement impact of its nuclear decommissioning and waste management costs, which has a risk reducing effect. However, Concentric observes that US nuclear utilities are generally subject to recovery mechanisms that similarly facilitate recovery of nuclear decommissioning and waste management costs and therefore OPG's circumstances are considered comparable to the proxy group in this regard.<sup>117</sup>
- *Capacity Refurbishment Variance Account* (per O. Reg. 53/05) – for the nuclear business, allows OPG to recover prudently-incurred costs incurred to increase the output, refurbish or add operating capacity, which for the nuclear business primarily relates to the DRP and enablement of Pickering extended operations. The account has risk reducing properties. However, with the DRP being the larger component, Concentric reviewed and concluded in an earlier section that similar regulatory protections for large nuclear construction projects are in place in other jurisdictions. In addition, many of the proxy companies have in place capital tracker mechanisms that allow for rate base treatment between rate cases.
- *Nuclear Development Variance Account* (per O. Reg. 53/05) – allows OPG to recover prudently incurred costs incurred for planning and preparation for the development of new nuclear generation facilities. While this account has risk reducing properties, as noted above, other jurisdictions provide similar regulatory protection for large nuclear construction projects.
- *Income and Other Taxes Variance Account* – records the impact of changes in tax legislation, reassessments of tax returns and similar changes, which reduces risk.

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<sup>116</sup> Ancillary Services Net Revenues Variance Account – Nuclear sub-account was not reviewed as it has historically had immaterial balances. Also not listed is the Pickering Closure Costs Deferral Account required pursuant to recent amendments to O. Reg. 53/05. As noted in an earlier section, that account serves to mitigate what would otherwise be a significant additional risk relative to EB-2016-0152 (and the proxy group), being the recovery of downsizing costs in connection with the planned Pickering shutdown during the upcoming rate term. The Rate Smoothing Deferral Account is also not identified as it functions solely as a collection deferral mechanism.

<sup>117</sup> For spent nuclear fuel long-term disposal, U.S. utilities have been subject to a pass through charge from the U.S. Department of Energy, which bears the ultimate obligation. This is in contrast to OPG, which bears the ultimate obligation for spent fuel disposal, in addition to nuclear station decommissioning.

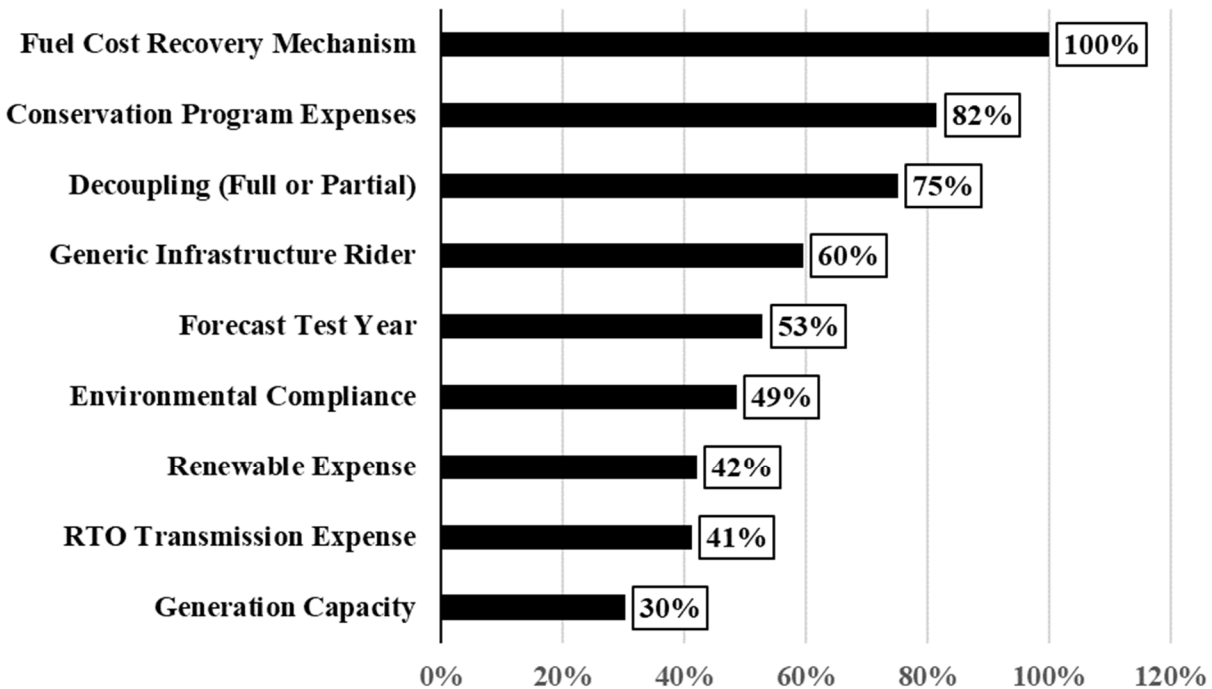


- *Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account and Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account* – established pursuant to an OEB requirement for OPG to bring forward accounting orders related to certain accounting changes to nuclear decommissioning and waste management liabilities and station end-of-life dates; these accounts have or are recording net credit balances to customers. On this basis, these accounts do not serve to reduce risk to OPG.
- *Bruce Lease Net Revenues Variance Account* (O. Reg. 53/05) – records variances in net earnings from OPG’s unregulated lease arrangement for the Bruce nuclear generating stations with Bruce Power. As this account uniquely relates to unregulated operations, it is not considered in Concentric’s risk profile analysis for OPG’s prescribed assets.
- *Pension and OPEB Cash Versus Cash Differential Deferral Account* – established to record the difference between accrual costs and cash amounts for pension and other post-employment benefit (“OPEB”) pending the outcome of the OEB’s consultation on regulatory treatment of pension and OPEB costs. The consultation has concluded, confirming the accrual accounting method as the default method for ratemaking. The purpose of the account was to facilitate a more in-depth review of recovery methodologies on a sector-wide basis, which had the effect of delaying OPG’s recovery of these amounts to the ultimate benefit of customers.

Additionally, as shown in Exhibit 5.1 and summarized in Figure 18 below, the operating utilities held by the proxy group companies have a number of different adjustment clauses and cost recovery mechanisms that provide risk mitigation.



**Figure 18: Summary of Regulatory Mechanisms for Concentric’s Proxy Group**



On the basis of the above, Concentric concludes that in this respect OPG is risk comparable to the proxy companies, assuming OPG’s existing deferral and variance accounts continue in the upcoming proceeding.

One important exception to this is OPG’s being entirely at risk related to variability in the output of its nuclear facilities. The companies in the proxy group do not face comparable risk, and, in fact, many recover costs through a mix of fixed and variable charges, and/or have decoupling in place. For the proxy companies, revenue decoupling mechanisms further reduce exposure to volumetric risk.

In addition to proxy group comparability, Concentric also considered the general comparability of OPG’s deferral and variance accounts to other regulated electric utilities in Ontario. In doing so, Concentric observed that the majority of OPG’s accounts would be classified as “Group 2” accounts according to the OEB’s Accounting Procedures Handbook. Group 2 accounts require a prudence review by the OEB before the utility is allowed to recover those costs. In contrast, Group 1 deferral and variance accounts do not require a prudence review.

Concentric reviewed the deferral and variance accounts for a sample of other regulated electric utilities in Ontario (including Hydro One Networks, Toronto Hydro, Hydro Ottawa, Niagara-on-the-Lake Hydro, and ENWIN) and determined that those companies have a mix of Group 1 and Group 2

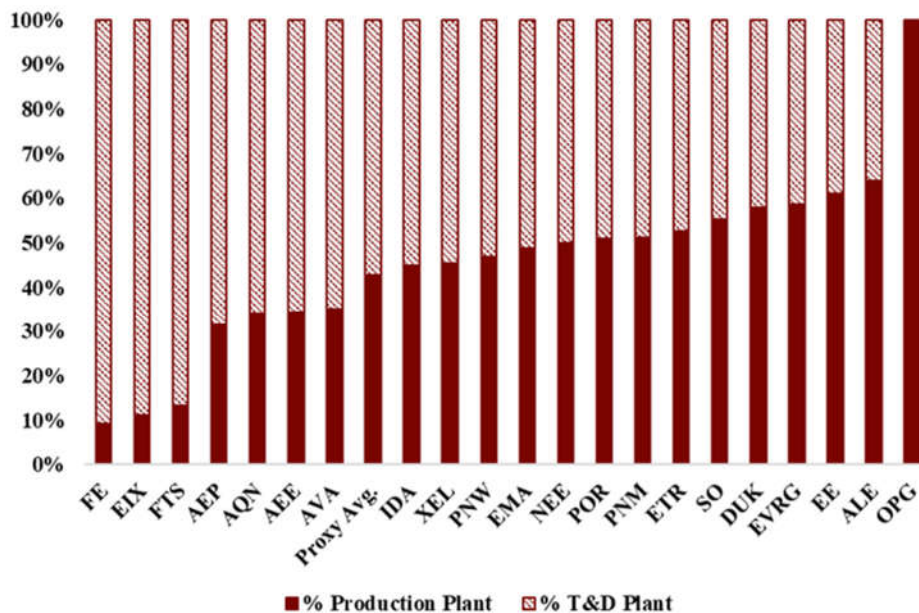


accounts. Because the disposition of Group 2 deferral and variance accounts involves a greater degree of regulatory scrutiny than Group 1 accounts, Concentric concludes that OPG has relatively greater risk of cost recovery for its deferral and variance accounts than do other electric utilities in Ontario.

**b. Generation percentage and mix**

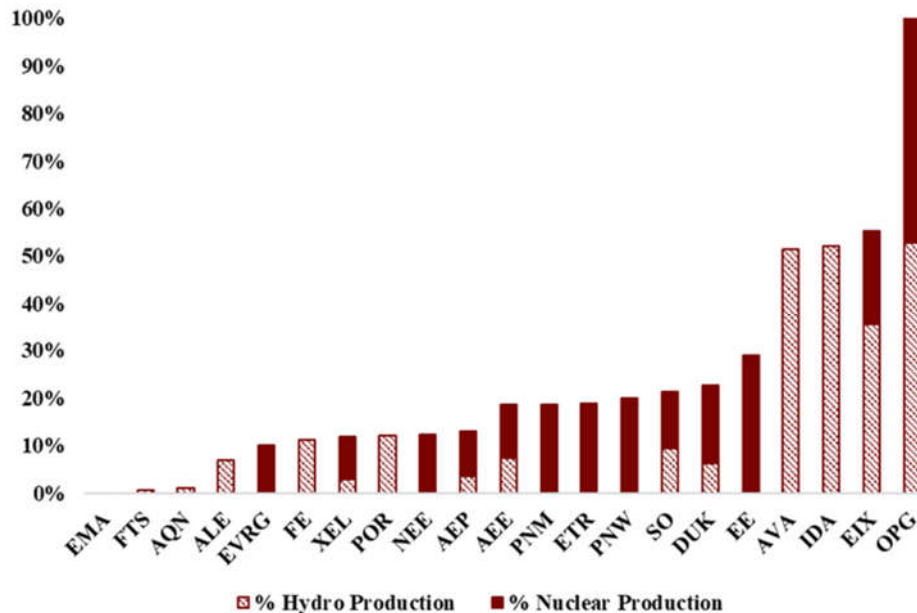
Concentric analyzed the generation percentage and mix of each proxy company to assess the percentage of each company’s assets that is generation, and further, the percentage of generation capacity that is comprised of nuclear generation. As shown in Figure 19 and Figure 20, OPG is the only company in the proxy group that is a pure-play regulated generation company. OPG also has the highest percentages of nuclear and hydroelectric generation. As discussed above, the investment community generally considers the generation function to be higher risk than other regulated electric operations.

**Figure 19: Generation versus Transmission and Distribution Assets**





**Figure 20: Generation Mix (MW), Percentage Hydro and Nuclear Generation**



## 6. Proxy Group Financial Risk Analysis

In order to assess the financial risk of OPG relative to the proxy group, Concentric analyzed the allowed common equity ratios at the operating company level and the actual book equity ratios for these companies at both the holding company and operating company level. Concentric analyzed these different variants of equity ratios in order to provide a range of observations. Book equity ratios at the holding company level, however, reflect a different risk profile than pure regulated utility operations, and Concentric has applied less weight to those results.

The proxy group mean and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for OPG, after consideration of differences in risk profiles between OPG and the proxy group. Specifically, the mean is “generally the best measure of central location for purposes of statistical inference,”<sup>118</sup> while also being at risk of being “unduly influenced by extreme observations.”<sup>119</sup> The median, or middle point of a set of observations at which half of the set of observations are above it and half and below it, is not subject to the same distortion due to extreme observations.<sup>120</sup> Figure 21 and Figure 22 summarize the

<sup>118</sup> Keller and Warrack, *Statistics for Management and Economics*, 5e ed., Duxbury Thompson Learning, 2000, at 92.

<sup>119</sup> *Ibid.*

<sup>120</sup> *Ibid.*, at 93.



results in tabular format for the Concentric Proxy Group and Moody's Peer Group, respectively. Schedules 1 through 3 provide the analysis summarized in Figure 21 and Figure 22.

**Figure 21: Concentric Proxy Group Equity Ratios**

<b>Company</b>	<b>Operating Subsidiaries: Avg. Authorized Equity Ratios (%)<sup>121</sup></b>	<b>Operating Subsidiaries: 5-Year Avg. Actual Equity Ratios (%)<sup>122</sup></b>	<b>Holding Company: 5-Year Avg. Actual Equity Ratios (%)<sup>123</sup></b>
ALE	53.81	58.79	58.44
AEE	50.00	52.90	49.34
AEP	46.07	48.91	47.88
AVA	49.36	50.56	50.34
DUK	52.26	53.00	47.02
EIX	52.00	55.36	43.98
EE	48.57	48.88	47.70
ETR	47.89	48.58	36.96
FE	48.00	55.63	26.82
EVRG	50.37	54.84	54.70
IDA	49.90	53.82	56.20
NEE	48.00	61.13	49.08
PNW	55.80	54.08	53.68
PNM	48.11	48.57	42.32
POR	50.00	50.05	51.18
SO	55.25	51.97	38.36
XEL	54.41	54.36	44.10
AQN	48.49	56.59	39.73
EMA	37.50	48.26	39.03
FTS	43.61	49.87	38.08
<b>Mean</b>	<b>49.47</b>	<b>52.81</b>	<b>45.75</b>
<b>Median</b>	<b>49.63</b>	<b>52.95</b>	<b>47.36</b>
OPG	45.00	45.00	45.00

<sup>121</sup> See, Exhibit 2.1.

<sup>122</sup> See, Exhibit 3.1.

<sup>123</sup> See, Exhibit 4.1.



**Figure 22: Moody’s Proxy Group Equity Ratios**

<b>Company</b>	<b>Operating Subsidiaries: Avg. Authorized Equity Ratios (%)<sup>124</sup></b>	<b>Operating Subsidiaries: 5-Year Avg. Actual Equity Ratios (%)<sup>125</sup></b>	<b>Holding Company: 5-Year Avg. Actual Equity Ratios (%)<sup>126</sup></b>
PEG	54.00	53.55	54.46
NEE	48.00	61.13	49.08
EXC	50.05	53.06	48.24
<b>Mean</b>	<b>50.68</b>	<b>55.91</b>	<b>50.59</b>
<b>Median</b>	<b>50.05</b>	<b>53.06</b>	<b>49.08</b>
OPG	45.00	45.00	45.00

As shown in Figure 21 and Figure 22, OPG’s deemed equity ratio of 45% is lower than the average and median equity ratios Concentric identified for both proxy groups and all three analytical approaches. The mean and median equity ratios at the operating company level exceed 49% for both proxy groups. Further, the mean and median equity ratios at the holding company level exceed 49% for the Moody’s Peer Group. Only the mean and median equity ratios at the holding company level for the Concentric proxy group are lower than 49%. OPG’s deemed equity ratio is 0.75 to 10.91 percentage points below the results of Concentric’s analysis, depending on the proxy group and analytical approach employed.

The only authorized equity ratios lower than OPG’s are those for Emera and Fortis, both with lower risk T&D operations and no nuclear generation.<sup>127</sup> Certain U.S. companies produce analytical results close to OPG’s deemed equity ratio, but these companies also have substantial T&D assets to mitigate their generation risk. As discussed previously, generation assets are generally considered riskier from an investment perspective than T&D assets because generation assets typically have longer construction lead times, are subject to production risk and to risk from changes in environmental regulations and requirements and are more subject to technological obsolescence. For example, in EB-2007-0905, the OEB concluded: “OPG’s nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation.”<sup>128</sup> In that same decision, the OEB also commented on the relative risk of generation as

<sup>124</sup> See, Exhibit 2.2.

<sup>125</sup> See, Exhibit 3.2.

<sup>126</sup> See, Exhibit 4.2.

<sup>127</sup> In addition, both Emera and Fortis have substantial Canadian operations, and Canadian utilities have historically been authorized lower equity ratios than their U.S. counterparts, an outcome that Concentric does not believe reflects the converged risk profiles of Canadian and U.S. regulatory jurisdictions, as discussed earlier.

<sup>128</sup> EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.



follows: “The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation.”<sup>129</sup>

Figure 19 presented earlier, provides the percentage of generation assets and T&D assets for OPG and the proxy group companies. As shown in Figure 19 100% of OPG’s assets are dedicated to generation, while the proxy group companies have a mixture of generation assets and T&D assets. On that basis, we conclude that OPG has higher business risk than the proxy group companies, which suggests a higher deemed equity ratio is appropriate for OPG.

With the lower deemed equity ratio of OPG compared to the proxy group companies, Concentric concludes that OPG has greater financial risk than the proxy group. Concentric also considers that OPG is rated three notches lower than its issuer rating on a stand-alone basis according to S&P and Moody's, which places it toward the low end or below the investment grade credit rating range relative to the proxy group. This higher financial risk profile of OPG suggests its deemed equity ratio should fall at the upper end of the proxy group.

Further, Concentric notes that Georgia Power has been allowed to maintain an equity ratio of 56% for ratemaking purposes during the construction of Vogtle plant units 3 and 4 in recognition of the cash flow pressure during this large construction project. In particular, on December 17, 2019, the Georgia PSC approved a settlement agreement for a three-year rate plan that included an ROE of 10.50% on 56% common equity. In its Order approving the settlement, the Commission noted that Staff had recommended an equity ratio of 51%; however, the Commission determined that: “[b]ased on the evidence presented, the Commission finds and concludes that a capital structure of 56% common equity level is just and reasonable, and will help to mitigate the risk of a credit rating downgrade.”<sup>130</sup>

### **Comparative Analysis Conclusions**

Based on the comparative analyses of business and financial risk, Concentric draws the following conclusions:

- OPG’s generation mix is comprised of more nuclear generation than the proxy group, indicating that OPG is riskier than the group on this factor.
- OPG has an asset mix that is 100% generation in contrast to the proxy group companies with an average of 43%, indicating OPG is a riskier business.

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<sup>129</sup> *Ibid.*

<sup>130</sup> Docket 42516, Order, at 6.



- Unlike other proxy group companies with nuclear operations, OPG is fully subject to revenue variability risk on its nuclear generation, which significantly increases risk;
- OPG has several deferral and variance accounts for its operations, as do other proxy companies; therefore, OPG is considered to be risk comparable to the proxy group in this area. Several of OPG's accounts pertain to nuclear refurbishment and new nuclear planning, for which similar protections are provided for nuclear utilities in other jurisdictions;
- OPG's deemed equity ratio is lower and its stand-alone credit rating (by S&P) is weaker than the vast majority of the proxy companies, exposing OPG to more financial risk than the proxy companies.

On a relative risk basis, Concentric finds OPG, with its significant nuclear concentration, a pure generating company business profile, higher nuclear variability risk and higher financial risk, to fall towards the upper end of the spectrum of risk profiles established by the proxy companies. Depending on the analytical approach employed, and proxy group studied, the proxy group's mean equity ratio ranges between 45.75% and 55.91%. As discussed earlier in the report, however, Concentric places less weight on the equity ratios at utility holding companies (versus those at regulated operating companies) because those companies reflect a different risk profile than the regulated operations of OPG. Focusing on the results from the regulated operating companies, both actual and authorized equity ratios, produces a reasonable range of equity thickness for OPG of 49.47% to 55.91%.

OPG's current equity ratio of 45% is below those ranges despite OPG's elevated level of risk relative to the proxy groups. Given the risk factors noted above, OPG falls toward the upper end of the risk spectrum, and its equity ratio could reasonably be set at 55% to 56%, being the upper end of the proxy group results. In consideration of the results of our analysis together with the OEB's findings in EB-2016-0152, however, Concentric conservatively recommends an equity ratio of no less than 50% for OPG for this upcoming rate setting period.



## APPENDIX A: NUCLEAR RISK – CREDIT RATING AGENCIES

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This appendix provides excerpts from S&P Global Ratings highlighting that ratings agency’s views on the high-risk nature of utilities’ nuclear businesses.

Ameren (AEE) – “Higher operational risk and material ESG considerations from owning and operating the Callaway nuclear plant... Nuclear generation increases operational risks and carries with it long-term storage concerns; this is partially offset by the technology’s emission-free generation... Our negative comparable rating analysis modifier reflects the consolidated exposure to nuclear and coal generation... Environmental factors are material to our credit analysis primarily due to Ameren’s exposure to nuclear and coal generation.”<sup>131</sup>

Dominion Energy, Inc. (D) – “Overall, we assess most of the DEI utilities as very low risk and consistent with their effective management style of regulatory risk. The exception is DESC (Dominion Energy South Carolina) whose effectiveness in managing regulatory risk eroded after construction of two new nuclear units was cancelled. Despite DEI’s acquisition of DESC, our assessment of DESC incorporates a much less supportive regulatory environment in South Carolina than before the company’s cancellation of the nuclear plants... The company also has nuclear and renewable merchant generation businesses, which account for about 5% of EBITDA... We assess the merchant nuclear contracted asset as having the highest risk from the company’s portfolio of contracted assets. The merchant nuclear exposes the company to higher operating risks, volumetric risks, counterparty credit risk, and commodity risks. ”<sup>132</sup>

Duke (DUK) – “[T]he company’s carbon-free nuclear generation portfolio increases its operating risk and exposes it to longer-term nuclear waste storage risks despite the company’s long-term track record of achieving safe operational standards of its nuclear fleet.”<sup>133</sup>

Entergy (ETR) – “Remaining exposure to nuclear generation increases operational risk... Entergy continues to shut down nuclear plants. The company is reducing its exposure to non-regulated nuclear power units. It shut down a unit at its Indian Point facility in New York in spring 2020, and it plans to shut down the remaining operating unit in spring 2021. Its Palisades facility

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<sup>131</sup> S&P Ratings Direct, “Ameren Corp.,” April 10, 2020.

<sup>132</sup> S&P Ratings Direct, “Dominion Energy Inc. and Subsidiaries Outlooks Revised To Positive Due On Planned Asset Sale and Cancelled Pipeline Project,” July 7, 2020.

<sup>133</sup> S&P Ratings Direct, “Duke Energy Corp. And Subsidiaries Outlooks Affirmed Following Atlantic Cost Pipeline Exit; Outlook Stable,” July 9, 2020.



in Michigan will close in 2022... The stable outlook over the next two years reflects our expectation that Entergy will successfully exit its higher-risk, non-utility nuclear power generation stations and grow through its lower-risk, rate-regulated utility businesses, leading to an improved business risk profile... We could lower our ratings on Entergy over the next 24 months if its non-utility-owned nuclear power generation stations, which we currently expect to close, remain open and we anticipate that its financial measures will weaken, including adjusted FFO to debt of consistently below 14%... We expect that Entergy will close its remaining non-utility nuclear generating units in New York and Michigan over the next several years. Its business will largely consist of lower-risk, rate-regulated utility operations. As it moves toward becoming a fully rate-regulated utility company, we expect that its business risk profile will improve. Entergy's complete exit from the merchant nuclear business depends on the receipt of various regulatory approvals, particularly to sell the nuclear units for decommissioning... The company's current generation capacity of about 22,70021 MW consists of 6665% natural gas, 2325% nuclear, and about 10% coal... the company's board structure includes a nuclear committee, members of which discuss safety risks and best practices for its nuclear fleet."<sup>134</sup>

NextEra (NEE) – “[W]e assess the company at the very low end of the range for this category, incorporating the company's other higher-risk businesses. These include nuclear merchant generation, proprietary trading, retail supply and wholesale full-requirements contracts, and natural gas exploration and production businesses.”<sup>135</sup>

Pinnacle West Capital Corp (PNW) – “Environmental risks and potential liabilities associated with the company's coal-fired and nuclear generation capacity... Offsetting our assessment of PWCC's business risk profile are the company's limited regulatory diversity, the highly politicized regulatory environment in Arizona, environmental risks associated with the company's coal-fired generation, and operating risks associated with the company's nuclear generation. APSC owns 6,316 MW of regulated generating capacity, of which about 58% is from nuclear and coal-fired fuel sources. Because of these weaknesses, we assess PWCC's business risk profile as being in the lower half of its business risk profile category... The generation mix for APSC consists of about 57% natural gas, 21% coal, 18% nuclear, and 3% renewables... Additionally, APSC maintains sole management responsibility for the nation's largest nuclear plant, Palo Verde, with total generation capacity of

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<sup>134</sup> S&P Ratings Direct, “Entergy Corp.,” July 7, 2020.

<sup>135</sup> S&P Ratings Direct, “NextEra Energy Inc. Ratings Affirmed On Acquisition Of Gulf Power; Outlook Remains Stable,” January 3, 2019.



almost 4,000 MW. Although it's carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks."<sup>136</sup>

Southern (SO) – “Atlanta-based Southern Co. announced its share of the Vogtle units 3 and 4 nuclear power construction project costs have increased by approximately \$150 million... This follows a series of other related announcements by the company, including that it resequenced its planned construction activities for the units, and reduced its work force at the construction site by about 20%, primarily due to the outbreak of COVID-19, where multiple workers at the site have tested positive for the virus... We view these developments as indicative of potentially heightened business risk for Southern Co., and its key subsidiary, Georgia Power Co. given the challenging operating environment that COVID-19 presents, despite the company's view that it can achieve its required in-service date for units 3 and 4 by November 2021 and November 2022, respectively... The negative outlooks for Southern and its subsidiaries reflect the potential for increased business risk for Southern Co., given the scale of its nuclear construction activities at Vogtle units 3 and 4 amid the COVID-19 pandemic. The negative outlooks also reflect minimal financial cushion at the parent for the current rating, including consolidated FFO to debt of 16% for the next two years...”

**“We believe there is risk of delays to the project's regulatory in-service date.** While the company maintains that it can achieve its aggressive in-service date for units 3 and 4, we note that these estimates are based on several assumptions, including the company's view that the normal rate of absenteeism and its productivity targets can be met despite the temporary reduction in workers at the site, and despite the COVID-19 environment. The staff of the Georgia Public Service Commission (GPSC) has effectively cast doubt on the company's scheduled timeline to bring the units online, including for both the regulatory timeline, and the company's aggressive timeline. Furthermore, while the November 2021 and November 2022 regulatory in-service dates for units 3 and 4 remain the focus, the company is exposed to the risk of additional penalties on its nuclear construction cost recovery (NCCR) tariff, including a return on equity (ROE) that will be reduced by 10 basis points each month if units 3 and 4 are not commercially operational by June 1, 2021, and June 1, 2022.”<sup>137</sup>

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<sup>136</sup> S&P Ratings Direct, “Transaction Update: Pinnacle West Capital Corp.,” November 3, 2020.

<sup>137</sup> S&P Ratings Direct, “Research Update: Southern Company and Subsidiaries Outlooks Remain Negative on Higher Nuclear Construction Costs, Ratings Affirmed,” August 6, 2020.



Xcel (XEL) – “Xcel's fuel mix consists of approximately 23% renewables, 13% nuclear, 23% natural gas, and 37% coal... Additionally, Xcel operates two nuclear plants, expected to remain open through 2034, that generate around 1,700 MW of power. Although carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks.”<sup>138</sup>

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<sup>138</sup> S&P Ratings Direct, “Xcel Energy Inc.,” June 2, 2020.



## APPENDIX B: PRECEDENT FOR CONSIDERING U.S. DATA

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There is precedent among Canadian regulators for considering U.S. data and a U.S. proxy group for cost of capital evaluations. In recent orders, other Canadian regulators have determined that it is appropriate to consider the use of U.S. data and U.S. proxy groups to estimate the allowed return on equity (“ROE”) for a Canadian regulated utility. Regulators in Canada have noted several reasons that support consideration of U.S. data. First, the development of a proxy group comprised entirely of Canadian electric utilities is difficult due to the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than the provision of regulated electric utility service. Second, this problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies. The question for Canadian regulators has become: How do we account for any differences in risk between U.S. and Canadian utilities?

Concentric’s research and analysis demonstrate that it is possible to select a group of U.S. electric utilities that is comparable to Canadian utilities in terms of business and operating risk. In that regard, Concentric agrees with the conclusion of the OEB that it is not necessary to find that utilities are the same, only that they are comparable,<sup>139</sup> and with the National Energy Board’s (“NEB”) (predecessor to the Canadian Energy Regulator) conclusion that it is possible to account for differences in risk that would influence an investor’s required rate of return.<sup>140</sup>

A growing number of Canadian utility regulators have accepted the use of U.S. data or U.S. proxy groups in recent years. For example, in its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. The NEB appears to view U.S. market returns as valuable information in establishing the cost of capital for Canadian utilities. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.<sup>141</sup> Importantly, the NEB also found that the regulatory

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<sup>139</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, at 21.

<sup>140</sup> National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 71.

<sup>141</sup> *Ibid.*, at 66-72.



regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries, stating:

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*The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.<sup>142</sup>*

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Likewise, the OEB concluded that the U.S. is a relevant source of comparable data and that it often looks to the U.S. to inform its decisions:

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*The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*

*Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.<sup>143</sup>*

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Finally, the British Columbia Utilities Commission (“BCUC”) accepted the use of U.S. data, stating:

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*In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel*

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<sup>142</sup> *Ibid.*

<sup>143</sup> Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, at 23.



*considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.<sup>144</sup>*

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The BCUC affirmed this position in its 2013 Generic Cost of Capital Decision:

*The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.*

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And,

*[I]n the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.<sup>145</sup>*

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In summary, regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are often limited by the small number of publicly-traded utilities. They have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes. Therefore, they have determined that it is reasonable and appropriate to consider the results of a risk comparable U.S. proxy group for purposes of cost of capital analyses for a Canadian natural gas or electric utility. These findings suggest that it is reasonable and appropriate to consider a proxy group of U.S. utility companies as sufficiently comparable to Canadian regulated utilities in terms of their risk profile.

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<sup>144</sup> British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 16.

<sup>145</sup> British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage I), Decision, May 10, 2013, at 20.



## **APPENDIX C: RESUME OF JAMES M. COYNE**

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### **JAMES M. COYNE**

Senior Vice President

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Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

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### **AREAS OF EXPERTISE**

#### Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

#### Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

#### Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

#### Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages



## **PROFESSIONAL HISTORY**

### **Concentric Energy Advisors, Inc. (2006 – Present)**

Senior Vice President

Vice President

### **FTI Consulting (Lexecon) (2002 – 2006)**

Senior Managing Director – Energy Practice

### **Arthur Andersen LLP (2000 – 2002)**

Managing Director, Andersen Corporate Finance – Energy and Utilities

### **Navigant Consulting, Inc. (1996 – 2000)**

Managing Director, Financial Services Practice

Senior Vice President, Strategy Practice

### **TotalFinaElf (1990 – 1996)**

Manager, Corporate Planning and Development

Manager, Investor Relations

Manager of Strategic Planning and Vice President, Natural Gas Division

### **Arthur D. Little, Inc. (1989 – 1990)**

Senior Consultant – International Energy Practice

### **DRI/McGraw-Hill (1984 – 1989)**

Director, North American Natural Gas Consulting

Senior Economist, U.S. Electricity Service

### **Massachusetts Energy Facilities Siting Council (1982 – 1984)**

Senior Economist – Gas and Electric Utilities

### **Maine Office of Energy Resources (1981 – 1982)**

State Energy Economist

## **EDUCATION**

### **University of New Hampshire**

M.S., Resource Economics, *with honors*, 1981

### **Georgetown University**

B.S., Business Administration and Economics, *cum laude*, 1975

## **DESIGNATIONS AND AFFILIATIONS**

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001



American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

## **PUBLICATIONS AND RESEARCH**

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

## **SELECTED SPEAKING ENGAGEMENTS**

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.



“Understanding Regulated Utilities in Today’s Capital Markets”, NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

“Rate of Return: Where the Regulatory Rubber Meets the Road,” CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

“Innovations in Utility Business Models and Regulation”, The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

“M&A and Valuations,” Panelist at Infocast Utility Scale Solar Summit, September 2010

“The Use of Expert Evidence,” The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

“A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.”, The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

“Nuclear Power on the Verge of a New Era,” moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

“The Investment Implications of the Repeal of PUCHA,” Skadden Arps Client Conference, New York, NY, October 2005

“Anatomy of the Deal,” First Annual Energy Transactions Conference, Newport, RI, May 2005

“The Outlook for Wind Power,” Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

“Direction of U.S. M&A Activity for Utilities,” Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

“Outlook for U.S. Merger & Acquisition Activity,” Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

“Investor Perspectives on Emerging Energy Companies,” Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

“Electric Generation Asset Transactions: A Practical Guide,” workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

“New Strategic Options for the Power Sector,” Electric Utility Business Environment Conference, Denver, CO, May 1999

“Electric and Gas Industries: Moving Forward Together,” New England Gas Association Annual Meeting, November 1998

“Opportunities and Challenges in the Electric Marketplace,” Electric Power Research Institute, July 1998



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
<b>Alberta Beverage Container Management Board</b>				
Alberta Beverage Container Management Board	2016 2019- 2020	Expert for the Board	N/A	Return Margin on Bottle Depots
<b>Alberta Utilities Commission</b>				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
<b>American Arbitration Association</b>				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
<b>British Columbia Utilities Commission</b>				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	Project 3698852	Cost of Capital (Gas and Electric Distribution)
<b>California Utilities Commission</b>				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Gas Distribution)
<b>Connecticut Department of Public Utility Control</b>				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
<b>Federal Energy Regulatory Commission</b>				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startran IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
PPL Electric Utilities Corp.	2020	PP&I Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
<b>Hawaii Public Utility Commission</b>				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
<b>Maine Public Utilities Commission</b>				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
<b>Maryland State Board of Contract Appeals</b>				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
<b>Massachusetts Superior Court</b>				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
<b>Minnesota Public Utilities Commission</b>				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
<b>Newfoundland and Labrador Board of Commissioners of Public Utilities</b>				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
<b>New Jersey Board of Public Utilities</b>				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
<b>Nova Scotia Utility and Review Board</b>				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
<b>Ontario Energy Board</b>				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
<b>Prince Edward Island Regulatory and Appeals Commission</b>				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
<b>Régie de l'énergie du Québec</b>				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
<b>South Dakota Public Service Commission</b>				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
<b>Texas Public Utility Commission</b>				



<b>SPONSOR</b>	<b>DATE</b>	<b>CASE/APPLICANT</b>	<b>DOCKET</b>	<b>SUBJECT</b>
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
<b>U.S. Department of Commerce</b>				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
<b>Vermont Public Service Board</b>				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
<b>Wisconsin Public Service Commission</b>				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
<b>Yukon Utilities Board</b>				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)



## **APPENDIX D: RESUME OF DANIEL S. DANE**

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### **DANIEL S. DANE, CPA** Senior Vice President

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Daniel S. Dane has 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

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### **PROFESSIONAL HISTORY**

#### **Concentric Energy Advisors, Inc. (2004 – Present)**

##### **CE Capital Advisors, Inc.**

Senior Vice President (Concentric/CE Capital)

Financial and Operations Principal (CE Capital)

#### **Ernst & Young (2000 – 2001, 2003 – 2004)**

Staff Auditor and Database Management Associate

#### **ZIA Information Analysis Group (1997 – 2000)**

### **EDUCATION**

#### **Boston College**

M.B.A., 2003

#### **Colgate University**

B.A., Economics, 1996



## REPRESENTATIVE PROJECT EXPERIENCE

### Ratemaking and Utility Regulation Assignments

#### Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state administrative rate setting and merger approval proceedings regarding merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development.

#### Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; regulatory lag; and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

### Financial Advisory Assignments

#### Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately \$2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation and natural gas pipeline facilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services provided to U.S. and Canadian investor-owned utilities.

#### Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

### Litigation Advisory Assignments

Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

### Management and Operations Consulting Assignments

Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.



## **DESIGNATIONS AND PROFESSIONAL AFFILIATIONS**

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

American Institute of Certified Public Accountants, 2011

## **CERTIFICATIONS**

Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

## **PRESENTATIONS**

“Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs.” Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).

“Financial Management and Capital Markets.” University of Idaho Utility Executive Course, 2018.

“Increasing Shareholder Value through the Capital Markets.” University of Idaho Utility Executive Course, 2015, 2016 and 2017.

“A Comparative Analysis of Return on Equity of Natural Gas Utilities” (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
<b>Connecticut Public Utilities Regulatory Authority</b>				
SJW Group and Connecticut Water Service, Inc.	4/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study Cash Working Capital
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-lag Study Cash Working Capital
<b>Illinois Commerce Commission</b>				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition
<b>Maine Public Utilities Commission</b>				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
<b>Massachusetts Department of Public Utilities</b>				
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Revenue Requirement Lead-lag Study Cash Working Capital
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017; Administrative and General Expense Allocations
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Revenue Requirement Lead-lag Study Cash Working Capital
<b>New Hampshire Public Utilities Commission</b>				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
<b>New Mexico Public Regulation Commission</b>				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study Cash Working Capital
<b>Public Utility Commission of Texas</b>				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
<b>South Dakota Public Service Commission</b>				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity
<b>Vermont Public Utility Commission</b>				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., and any other necessary affiliates entities to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer
<b>Ontario Energy Board</b>				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Capital Structure

**Concentric Proxy Group Screening Data**

Proxy Group Company	Ticker	Regulated Generation Assets in Rate Base?	% of Regulated Generation		Regulated Revenue as a % of Total Revenue	Regulated Income as a % of Total Income	Regulated Electric Revenue as a % of Regulated Revenue	Regulated Electric Income as a % of Regulated Income	Investment Grade Credit Rating?
			Nuclear	Hydro					
		[1]	[1]	[1]	[2]	[2]	[2]	[2]	[1]
ALLETE, Inc.	ALE	Yes	0.00%	7.01%	73.45%	75.04%	97.70%	97.43%	Yes
Ameren Corporation	AEE	Yes	11.15%	7.36%	100.00%	100.00%	86.10%	88.30%	Yes
American Electric Power Company, Inc.	AEP	Yes	9.47%	3.59%	89.15%	95.59%	100.00%	100.00%	Yes
Avista Corporation	AVA	Yes	0.00%	51.45%	98.28%	100.00%	100.00%	100.00%	Yes
Duke Energy Corporation	DUK	Yes	16.39%	6.27%	98.18%	100.00%	93.37%	93.07%	Yes
Edison International	EIX	Yes	19.85%	35.44%	99.59%	94.78%	100.00%	100.00%	Yes
El Paso Electric Company	EE	Yes	29.04%	0.00%	100.00%	100.00%	100.00%	100.00%	Yes
Entergy Corporation	ETR	Yes	18.49%	0.34%	84.88%	100.00%	98.54%	98.85%	Yes
FirstEnergy Corporation	FE	Yes	0.00%	11.11%	100.00%	100.00%	100.00%	100.00%	Yes
Evergy, Inc.	EVRG	Yes	10.02%	0.05%	100.00%	100.00%	100.00%	100.00%	Yes
IDACORP, Inc.	IDA	Yes	0.00%	52.14%	99.71%	98.87%	100.00%	100.00%	Yes
NextEra Energy, Inc.	NEE	Yes	12.21%	0.00%	69.38%	70.04%	100.00%	100.00%	Yes
Pinnacle West Capital Corporation	PNW	Yes	20.04%	0.00%	99.90%	100.00%	100.00%	100.00%	Yes
PNM Resources, Inc.	PNM	Yes	18.54%	0.00%	100.00%	99.96%	100.00%	100.00%	Yes
Portland General Electric Company	POR	Yes	0.00%	12.16%	100.00%	100.00%	100.00%	100.00%	Yes
Southern Company	SO	Yes	11.97%	9.37%	90.47%	95.71%	84.46%	81.27%	Yes
Xcel Energy Inc.	XEL	Yes	9.03%	2.87%	99.32%	100.00%	85.46%	87.45%	Yes
Algonquin Power & Utilities Corp [2]	AQN	Yes	0.00%	1.07%	81.85%	81.58%	49.13%	49.13%	Yes
Emera Inc.	EMA	Yes	N/A	N/A	90.86%	100.00%	84.19%	87.49%	Yes
Fortis Inc.	FTS	Yes	0.00%	0.68%	97.52%	100.00%	75.63%	76.49%	Yes

Notes:

- [1] Per S&P Global Market Intelligence
- [2] Per company 10-Ks and annual reports

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
ALLETE, Inc.	Minnesota	Minnesota Power	Electric	Vertically Integrated	3/12/2018	53.81%	146,741	78,961	53.81%
Ameren Corporation	Illinois	Ameren Illinois Company	Electric	Distribution	12/16/2019	50.00%	1,220,680	610,340	
Ameren Corporation	Illinois	Ameren Illinois Company	Natural Gas	Distribution	11/1/2018	50.00%	812,267	406,134	
Ameren Corporation	Missouri	Union Electric Company	Electric	Vertically Integrated	3/18/2020	N/A	N/A	N/A	
Ameren Corporation	Missouri	Union Electric Company	Natural Gas	Distribution	8/21/2019	N/A	N/A	N/A	50.00%
American Electric Power Company, Inc.	Arkansas [1]	Southwestern Electric Power Company	Electric	Vertically Integrated	12/20/2019	44.60%	119,644	53,363	
American Electric Power Company, Inc.	Indiana [1]	Indiana Michigan Power Company	Electric	Vertically Integrated	5/30/2018	46.32%	465,774	215,737	
American Electric Power Company, Inc.	Kentucky	Kentucky Power Company	Electric	Vertically Integrated	1/18/2018	41.68%	166,603	69,440	
American Electric Power Company, Inc.	Louisiana	Southwestern Electric Power Co.	Electric	Vertically Integrated	2/27/2013	N/A	N/A	N/A	
American Electric Power Company, Inc.	Michigan [1]	Indiana Michigan Power Co.	Electric	Vertically Integrated	1/23/2020	46.26%	129,418	59,871	
American Electric Power Company, Inc.	Ohio	Columbus Southern Power Company	Electric	Distribution	12/14/2011	50.64%	1,500,000	759,600	
American Electric Power Company, Inc.	Oklahoma	Public Service Co. of OK	Electric	Vertically Integrated	3/14/2019	N/A	N/A	N/A	
American Electric Power Company, Inc.	Tennessee	Kingsport Power Company	Electric	Vertically Integrated	8/9/2016	40.25%	48,032	19,333	
American Electric Power Company, Inc.	Texas	AEP Texas Central Co.	Electric	Distribution	12/13/2007	40.00%	1,029,536	411,814	
American Electric Power Company, Inc.	Texas	AEP Texas North Co.	Electric	Distribution	5/24/2007	N/A	N/A	N/A	
American Electric Power Company, Inc.	Texas	Southwestern Electric Power Co.	Electric	Vertically Integrated	12/14/2017	48.46%	185,508	89,897	46.07%
Avista Corporation	Alaska	Alaska Electric Light & Power	Electric	Vertically Integrated	11/15/2017	58.18%	17,165	9,987	
Avista Corporation	Idaho	Avista Corp.	Electric	Vertically Integrated	11/29/2019	50.00%	133,401	66,701	
Avista Corporation	Idaho	Avista Corp.	Natural Gas	Distribution	12/28/2017	50.00%	88,068	44,034	
Avista Corporation	Oregon	Avista Corp.	Natural Gas	Distribution	10/8/2019	50.00%	102,017	51,009	
Avista Corporation	Washington	Avista Corp.	Electric	Vertically Integrated	3/25/2020	48.50%	254,232	123,303	
Avista Corporation	Washington	Avista Corp.	Natural Gas	Distribution	3/25/2020	48.50%	164,915	79,984	49.36%
Duke Energy Corporation	Florida	Duke Energy Florida LLC	Electric	Vertically Integrated	10/25/2017	N/A	N/A	N/A	
Duke Energy Corporation	Indiana [1]	Duke Energy Indiana, LLC	Electric	Vertically Integrated	6/29/2020	53.91%	830,270	447,619	
Duke Energy Corporation	Kentucky	Duke Energy Kentucky Inc.	Electric	Vertically Integrated	4/27/2020	48.23%	142,393	68,676	
Duke Energy Corporation	Kentucky	Duke Energy Kentucky Inc.	Natural Gas	Distribution	3/27/2019	50.76%	100,040	50,780	
Duke Energy Corporation	North Carolina	Duke Energy Carolinas LLC	Electric	Vertically Integrated	6/22/2018	52.00%	2,005,333	1,042,773	
Duke Energy Corporation	North Carolina	Duke Energy Progress LLC	Electric	Vertically Integrated	2/23/2018	52.00%	1,411,441	733,949	
Duke Energy Corporation	North Carolina	Piedmont Natural Gas Co.	Natural Gas	Distribution	10/31/2019	52.00%	441,656	229,661	
Duke Energy Corporation	Ohio	Duke Energy Ohio Inc.	Electric	Distribution	12/19/2018	50.75%	718,099	364,435	
Duke Energy Corporation	Ohio	Duke Energy Ohio Inc.	Natural Gas	Distribution	11/13/2013	53.30%	431,666	230,078	
Duke Energy Corporation	South Carolina	Duke Energy Carolinas LLC	Electric	Vertically Integrated	5/1/2019	53.00%	591,113	313,290	
Duke Energy Corporation	South Carolina	Duke Energy Progress LLC	Electric	Vertically Integrated	5/8/2019	53.00%	169,208	89,680	
Duke Energy Corporation	South Carolina	Piedmont Natural Gas Co.	Natural Gas	Distribution	9/26/2018	53.00%	441,656	234,078	
Duke Energy Corporation	Tennessee	Piedmont Natural Gas Co.	Natural Gas	Distribution	1/23/2012	52.71%	184,982	97,504	52.26%
Edison International	California	Southern California Edison Co.	Electric	Vertically Integrated	12/19/2019	52.00%	5,111,838	2,658,156	52.00%
El Paso Electric Company	New Mexico	El Paso Electric Co.	Electric	Vertically Integrated	6/8/2016	49.29%	98,984	48,789	
El Paso Electric Company	Texas	El Paso Electric Co.	Electric	Vertically Integrated	12/14/2017	48.35%	323,297	156,314	48.57%
Entergy Corporation	Arkansas [1]	Entergy Arkansas LLC	Electric	Vertically Integrated	12/13/2019	47.04%	711,931	334,902	
Entergy Corporation	Louisiana	Entergy Gulf States LA LLC	Electric	Vertically Integrated	12/16/2013	N/A	N/A	N/A	
Entergy Corporation	Louisiana	Entergy Gulf States LA LLC	Natural Gas	Distribution	7/6/2005	47.52%	99,500	47,282	
Entergy Corporation	Louisiana	Entergy Louisiana LLC	Electric	Vertically Integrated	7/10/2014	N/A	N/A	N/A	
Entergy Corporation	Louisiana	Entergy New Orleans LLC	Electric	Vertically Integrated	11/7/2019	50.00%	202,634	101,317	
Entergy Corporation	Louisiana	Entergy New Orleans LLC	Natural Gas	Distribution	11/7/2019	50.00%	99,500	49,750	
Entergy Corporation	Mississippi	Entergy Mississippi LLC	Electric	Vertically Integrated	12/11/2014	N/A	N/A	N/A	
Entergy Corporation	Texas	Entergy Texas Inc.	Electric	Vertically Integrated	12/20/2018	N/A	N/A	N/A	47.89%

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
FirstEnergy Corporation	Maryland	Potomac Edison Co.	Electric	Distribution	3/22/2019	52.82%	268,830	141,996	
FirstEnergy Corporation	New Jersey	Jersey Cntrl Power & Light Co.	Electric	Distribution	12/12/2016	45.00%	1,131,190	509,036	
FirstEnergy Corporation	Ohio	Cleveland Elec Illuminating Co	Electric	Distribution	1/21/2009	49.00%	751,979	368,470	
FirstEnergy Corporation	Ohio	Ohio Edison Co.	Electric	Distribution	1/21/2009	49.00%	1,050,129	514,563	
FirstEnergy Corporation	Ohio	Toledo Edison Co.	Electric	Distribution	1/21/2009	49.00%	310,979	152,380	
FirstEnergy Corporation	Pennsylvania	Metropolitan Edison Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	Pennsylvania Electric Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	Pennsylvania Power Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	West Penn Power Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	West Virginia	Monongahela Power Co.	Electric	Vertically Integrated	2/4/2015	N/A	N/A	N/A	48.00%
Evergy, Inc.	Kansas	Evergy Kansas Central Inc.	Electric	Vertically Integrated	9/27/2018	51.24%	381,420	195,440	
Evergy, Inc.	Kansas	Evergy Metro Inc	Electric	Vertically Integrated	12/13/2018	49.09%	259,099	127,192	
Evergy, Inc.	Missouri	Evergy Metro Inc	Electric	Vertically Integrated	10/31/2018	N/A	N/A	N/A	
Evergy, Inc.	Missouri	Evergy Missouri West	Electric	Vertically Integrated	10/31/2018	N/A	N/A	N/A	50.37%
IDACORP, Inc.	Idaho	Idaho Power Co.	Electric	Vertically Integrated	12/30/2011	N/A	N/A	N/A	
IDACORP, Inc.	Oregon	Idaho Power Co.	Electric	Vertically Integrated	2/23/2012	49.90%	19,054	9,508	49.90%
NextEra Energy, Inc.	Florida	Florida Power & Light Co.	Electric	Vertically Integrated	11/29/2016	N/A	N/A	N/A	
NextEra Energy, Inc.	Florida	Gulf Power Co.	Electric	Vertically Integrated	4/4/2017	N/A	N/A	N/A	
NextEra Energy, Inc.	Florida [2]	Pivotal Utility Holdings Inc.	Natural Gas	Distribution	3/26/2018	48.00%	109,674	52,644	48.00%
Pinnacle West Capital Corporation	Arizona	Arizona Public Service Co.	Electric	Vertically Integrated	8/15/2017	55.80%	1,235,451	689,382	55.80%
PNM Resources, Inc.	New Mexico	Public Service Co. of NM	Electric	Vertically Integrated	12/20/2017	49.61%	526,346	261,120	
PNM Resources, Inc.	Texas	Texas-New Mexico Power Co.	Electric	Distribution	12/20/2018	45.00%	253,216	113,947	48.11%
Portland General Electric Company	Oregon	Portland General Electric Co.	Electric	Vertically Integrated	12/14/2018	50.00%	888,123	444,062	50.00%
Southern Company	Alabama	Alabama Power Co.	Electric	Vertically Integrated	10/12/1982	N/A	N/A	N/A	
Southern Company	Georgia	Atlanta Gas Light Co.	Natural Gas	Distribution	12/19/2019	56.00%	1,643,000	920,080	
Southern Company	Georgia	Georgia Power Co.	Electric	Vertically Integrated	12/17/2019	56.00%	2,536,685	1,420,544	
Southern Company	Georgia	Savannah Electric & Power Co.	Electric	Vertically Integrated	5/25/2005	N/A	N/A	N/A	
Southern Company	Illinois	Northern Illinois Gas Co.	Natural Gas	Distribution	10/2/2019	54.20%	2,226,874	1,206,966	
Southern Company	Mississippi	Mississippi Power Co.	Electric	Vertically Integrated	3/17/2020	53.00%	188,000	99,640	
Southern Company	Tennessee	Chattanooga Gas Co.	Natural Gas	Distribution	10/15/2018	49.23%	67,000	32,984	
Southern Company	Virginia	Virginia Natural Gas Inc.	Natural Gas	Distribution	12/21/2017	N/A	N/A	N/A	55.25%
Xcel Energy Inc.	Colorado	Public Service Co. of CO	Electric	Vertically Integrated	2/11/2020	55.61%	1,478,992	822,467	
Xcel Energy Inc.	Colorado	Public Service Co. of CO	Natural Gas	Distribution	12/21/2018	54.60%	1,400,000	764,400	
Xcel Energy Inc.	Minnesota	Northern States Power Co. - MN	Electric	Vertically Integrated	4/7/2020	N/A	N/A	N/A	
Xcel Energy Inc.	Minnesota	Northern States Power Co. - MN	Natural Gas	Distribution	12/6/2010	52.46%	250,000	131,150	
Xcel Energy Inc.	North Dakota	Northern States Power Co. - MN	Electric	Vertically Integrated	2/26/2014	52.56%	94,212	49,518	
Xcel Energy Inc.	North Dakota	Northern States Power Co. - MN	Natural Gas	Distribution	6/13/2007	51.59%	250,000	128,975	
Xcel Energy Inc.	New Mexico	Southwestern Public Service Co	Electric	Vertically Integrated	5/20/2020	54.77%	121,604	66,603	
Xcel Energy Inc.	South Dakota	Northern States Power Co. - MN	Electric	Vertically Integrated	6/15/2015	N/A	N/A	N/A	
Xcel Energy Inc.	Texas	Southwestern Public Service Co	Electric	Vertically Integrated	8/27/2020	54.62%	271,560	148,326	
Xcel Energy Inc.	Wisconsin	Northern States Power Co - WI	Electric	Vertically Integrated	9/4/2019	52.52%	300,000	157,560	
Xcel Energy Inc.	Wisconsin	Northern States Power Co - WI	Natural Gas	Distribution	9/4/2019	52.52%	100,000	52,520	54.41%

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
Algonquin Power & Utilities Corp	California	Liberty Utilities	Electric	Vertically Integrated	8/27/2020	52.50%	49,000	25,725	
Algonquin Power & Utilities Corp	Kansas	Empire District Electric Co.	Electric	Vertically Integrated	7/30/2019	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	Massachusetts	Liberty Utilities	Natural Gas	Distribution	2/10/2016	50.00%	50,000	25,000	
Algonquin Power & Utilities Corp	Missouri	Empire District Electric Co.	Electric	Vertically Integrated	7/1/2020	46.00%	154,042	70,859	
Algonquin Power & Utilities Corp	Missouri	Empire District Gas Co.	Natural Gas	Distribution	1/20/2010	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	Missouri	Liberty Utilities (Midstates)	Natural Gas	Distribution	6/6/2018	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	New Hampshire	Granite State	Electric	Distribution	6/30/2020	52.00%	44,092	22,928	
Algonquin Power & Utilities Corp	New Hampshire	EnergyNorth	Natural Gas	Distribution	2/28/2020	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	New Brunswick	Enbridge Gas New Brunswick	Natural Gas	Distribution	11/30/2010	45.00%	12,000	5,400	48.49%
Emera Inc.	Florida	Tampa Electric Co.	Electric	Vertically Integrated	11/6/2017	N/A	N/A	N/A	
Emera Inc.	New Mexico	New Mexico Gas Co.	Natural Gas	Distribution	7/17/2019	N/A	N/A	N/A	
Emera Inc.	Nova Scotia	Nova Scotia Power Inc.	Electric	Vertically Integrated	12/21/2012	37.50%	519,000	194,625	37.50%
Fortis Inc.	New York	Central Hudson Gas & Electric	Electric	Distribution	6/14/2018	48.00%	307,025	147,372	
Fortis Inc.	New York	Central Hudson Gas & Electric	Natural Gas	Distribution	6/14/2018	48.00%	82,462	39,582	
Fortis Inc.	Arizona	Tucson Electric Power Co.	Electric	Vertically Integrated	2/24/2017	50.03%	426,451	213,353	
Fortis Inc.	Arizona	UNS Electric Inc.	Electric	Vertically Integrated	8/18/2016	52.83%	97,926	51,734	
Fortis Inc.	Arizona	UNS Gas Inc.	Natural Gas	Distribution	4/24/2012	50.82%	582,074	295,810	
Fortis Inc.	Alberta	FortisAlberta Inc	Electric	Distribution	12/16/16 & 8/2/18	37.00%	564,000	208,680	
Fortis Inc.	British Columbia	FortisBC	Electric	Vertically Integrated	3/25/2014	40.00%	176,000	70,400	
Fortis Inc.	British Columbia	FortisBC Energy	Natural Gas	Distribution	8/10/2016	38.50%	1,030,000	396,550	
Fortis Inc.	Newfoundland & Labrador	Newfoundland Power Inc	Electric	Vertically Integrated	1/24/2019	45.00%	268,000	120,600	
Fortis Inc.	Prince Edward Island	Maritime Electric Company Ltd.	Electric	Vertically Integrated	9/27/2019	40.00%	81,000	32,400	43.61%
<b>Mean, All Results</b>						<b>49.52%</b>			<b>49.47%</b>
<b>Median, All Results</b>						<b>50.00%</b>			<b>49.63%</b>

Notes:

[1] Authorized equity ratio adjusted to remove zero cost of capital items from the capital structure.

[2] While zero cost of capital items are typically included in the capital structure for utilities operating in Florida, this case involved a settlement that was silent with respect to most traditional cost of capital parameters. Accordingly, no adjustment was made to remove zero cost of capital items from the capital structure.

Authorized Capital Structure Analysis - Moody's Proxy Group

Company	State	Subsidiary	Docket	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Avg. Equity Ratio
Public Service Enterprise Group, Inc.	New Jersey	Public Service Electric Gas	D-ER18010029	Electric	Distribution	10/29/2018	54.00%	
Public Service Enterprise Group, Inc.	New Jersey	Public Service Electric Gas	D-GR18010030	Natural Gas	Distribution	10/29/2018	54.00%	54.00%
NextEra Energy, Inc.	Florida	Florida Power & Light Co.	D-160021-EI	Electric	Vertically Integrated	11/29/2016	N/A	
NextEra Energy, Inc.	Florida	Gulf Power Co.	D-160186-EI	Electric	Vertically Integrated	4/4/2017	N/A	
NextEra Energy, Inc.	Florida	Pivotal Utility Holdings Inc.	20170179-GU	Natural Gas	Distribution	3/26/2018	48.00%	48.00%
Exelon Corporation	DC	Potomac Electric Power Co.	FC-1150	Electric	Distribution	8/8/2018	50.44%	
Exelon Corporation	Delaware	Delmarva Power & Light Co.	D-17-0977	Electric	Distribution	8/21/2018	50.52%	
Exelon Corporation	Delaware	Delmarva Power & Light Co.	D-17-0978	Natural Gas	Distribution	11/8/2018	50.52%	
Exelon Corporation	Illinois	Commonwealth Edison Co.	D-19-0387	Electric	Distribution	12/4/2019	47.97%	
Exelon Corporation	Maryland	Baltimore Gas and Electric Co.	C-9610 (EL)	Electric	Distribution	12/17/2019	N/A	
Exelon Corporation	Maryland	Baltimore Gas and Electric Co.	C-9610 (GAS)	Natural Gas	Distribution	12/17/2019	N/A	
Exelon Corporation	Maryland	Delmarva Power & Light Co.	C-9455	Electric	Distribution	7/14/2020	50.53%	
Exelon Corporation	Maryland	Potomac Electric Power Co.	C-9602	Electric	Distribution	8/12/2019	50.46%	
Exelon Corporation	New Jersey	Atlantic City Electric Co.	D-ER18080925	Electric	Distribution	3/13/2019	49.94%	
Exelon Corporation	Pennsylvania	PECO Energy Co.	D-R-2018-3000164	Electric	Distribution	12/20/2018	N/A	
Exelon Corporation	Pennsylvania	PECO Energy Co.	D-R-2010-2161592	Natural Gas	Distribution	12/16/2010	N/A	50.05%
<b>Mean</b>							<b>50.64%</b>	<b>50.68%</b>
<b>Median</b>							<b>50.49%</b>	<b>50.05%</b>

**CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP**

Proxy Group Company	Ticker	EQUITY RATIO [1]					Average
		2019	2018	2017	2016	2015	
ALLETE, Inc.	ALE	59.55%	61.27%	60.15%	57.01%	55.95%	58.79%
Ameren Corporation	AEE	52.85%	53.13%	53.05%	52.99%	52.51%	52.90%
American Electric Power Company, Inc.	AEP	49.44%	49.20%	49.57%	48.29%	48.06%	48.91%
Avista Corporation	AVA	50.83%	49.89%	50.75%	50.93%	50.41%	50.56%
Duke Energy Corporation	DUK	52.56%	52.50%	52.55%	52.14%	55.25%	53.00%
Edison International	EIX	53.79%	51.34%	57.19%	58.20%	56.29%	55.36%
El Paso Electric Company	EE	48.98%	47.88%	49.95%	47.73%	49.86%	48.88%
Entergy Corporation	ETR	48.21%	48.85%	47.79%	48.19%	49.87%	48.58%
FirstEnergy Corporation	FE	56.32%	58.90%	56.97%	54.59%	51.34%	55.63%
Energy, Inc.	EVRG	54.13%	54.93%	54.22%	55.08%	55.84%	54.84%
IDACORP, Inc.	IDA	55.14%	54.25%	54.22%	53.15%	52.34%	53.82%
NextEra Energy, Inc.	NEE	59.37%	63.95%	59.41%	62.29%	60.61%	61.13%
Pinnacle West Capital Corporation	PNW	52.80%	54.36%	53.14%	54.59%	55.50%	54.08%
PNM Resources, Inc.	PNM	47.68%	48.13%	49.03%	49.23%	48.79%	48.57%
Portland General Electric Company	POR	49.85%	50.19%	49.80%	49.82%	50.61%	50.05%
Southern Company	SO	54.20%	54.72%	49.24%	51.13%	50.58%	51.97%
Xcel Energy Inc.	XEL	54.29%	54.48%	54.23%	54.22%	54.59%	54.36%
Algonquin Power & Utilities Corp	AQN	57.80%	58.92%	55.52%	56.15%	54.58%	56.59%
Emera Inc.	EMA	48.06%	48.44%	49.22%	48.66%	46.92%	48.26%
Fortis Inc.	FTS	49.88%	48.98%	49.50%	50.13%	50.86%	49.87%
MEAN		52.79%	53.22%	52.77%	52.73%	52.54%	52.81%
LOW		47.68%	47.88%	47.79%	47.73%	46.92%	48.26%
HIGH		59.55%	63.95%	60.15%	62.29%	60.61%	61.13%

**EQUITY RATIO - UTILITY OPERATING COMPANIES [2]**

Company Name	Ticker	2019	2018	2017	2016	2015	Average
ALLETE (Minnesota Power)	ALE	59.59%	61.39%	60.04%	56.92%	55.86%	58.76%
Superior Water, Light and Power Company	ALE	58.08%	56.86%	64.99%	61.12%	60.23%	60.26%
Ameren Illinois Company	AEE	53.37%	53.27%	53.85%	53.95%	53.96%	53.68%
Union Electric Company	AEE	52.36%	53.00%	52.42%	52.30%	51.53%	52.32%
AEP Texas Central Company	AEP				46.01%	43.63%	44.82%
AEP Texas North Company	AEP				43.29%	42.36%	42.82%
Appalachian Power Company	AEP	48.74%	49.51%	48.72%	46.89%	46.77%	48.13%
Indiana Michigan Power Company	AEP	46.74%	44.62%	46.33%	49.11%	52.65%	47.89%
Kentucky Power Company	AEP	47.34%	45.72%	43.52%	43.45%	43.26%	44.66%
Kingsport Power Company	AEP	54.62%	50.79%	46.53%	65.24%	59.70%	55.38%
Ohio Power Company	AEP	54.50%	57.80%	58.63%	56.51%	50.09%	55.51%
Public Service Company of Oklahoma	AEP	49.69%	49.16%	48.50%	48.47%	46.45%	48.46%
Southwestern Electric Power Company	AEP	48.80%	46.97%	48.52%	45.95%	49.59%	47.97%
Transource Maryland, LLC	AEP	40.18%	41.81%				40.99%
Transource Pennsylvania, LLC	AEP	40.15%	41.92%				41.03%
Wheeling Power Company	AEP	53.51%	54.62%	54.26%	54.12%	53.73%	54.05%
Avista Corporation	AVA	50.83%	49.89%	50.75%	50.93%	50.41%	50.56%
Duke Energy Carolinas, LLC	DUK	52.11%	51.78%	52.98%	52.81%	58.07%	53.55%
Duke Energy Florida, LLC	DUK	49.91%	50.04%	49.25%	50.83%	55.28%	51.06%
Duke Energy Indiana, LLC	DUK	52.84%	53.26%	51.94%	51.59%	50.27%	51.98%
Duke Energy Kentucky, Inc.	DUK	49.37%	51.95%	53.11%	54.74%	56.11%	53.06%
Duke Energy Ohio, Inc.	DUK	65.22%	68.09%	66.24%	66.39%	68.71%	66.93%
Duke Energy Progress, LLC	DUK	51.29%	51.00%	52.27%	51.58%	52.40%	51.71%
Piedmont Natural Gas Company, Inc.	DUK		49.32%	44.79%	38.72%	42.06%	43.72%
Southern California Edison Company	EIX	53.79%	51.34%	57.19%	58.20%	56.29%	55.36%
El Paso Electric Company	EE	48.98%	47.88%	49.95%	47.73%	49.86%	48.88%
Entergy Arkansas, LLC	ETR	47.90%	49.42%	46.27%	46.54%	45.65%	47.16%
Entergy Louisiana, LLC	ETR	47.47%	47.37%	47.43%	47.87%	51.13%	48.25%
Entergy Mississippi, LLC	ETR	48.60%	49.11%	48.28%	49.58%	50.08%	49.13%
Entergy New Orleans, LLC	ETR	49.26%	51.19%	53.16%	54.81%	60.01%	53.69%
Entergy Texas, Inc.	ETR	50.92%	53.46%	50.45%	49.56%	49.96%	50.87%
Cleveland Electric Illuminating Company	FE	55.17%	55.44%	55.27%	50.89%	45.10%	52.37%
Jersey Central Power & Light Company	FE	68.33%	69.46%	65.30%	59.21%	52.32%	62.92%
Metropolitan Edison Company	FE	48.00%	53.21%	52.33%	50.30%	48.43%	50.45%
Monongahela Power Company	FE	46.36%	48.87%	49.15%	49.15%	48.89%	48.48%
Ohio Edison Company	FE	66.77%	69.93%	64.91%	63.66%	63.58%	65.77%
Pennsylvania Electric Company	FE	50.37%	53.89%	52.06%	51.85%	47.70%	51.18%
Pennsylvania Power Company	FE	48.79%	49.03%	53.82%	52.06%	58.16%	52.37%
Potomac Edison Company	FE	54.31%	52.35%	51.59%	50.08%	51.59%	51.98%
Toledo Edison Company	FE	59.74%	60.43%	60.04%	61.98%	60.41%	60.52%
West Penn Power Company	FE	47.69%	53.50%	52.82%	52.62%	49.48%	51.22%
Great Plains Energy Incorporated	EVRG	50.32%	51.05%	50.15%	51.15%	50.80%	50.70%
Westar Energy (KPL)	EVRG	57.97%	59.08%	58.74%	59.68%	62.21%	59.54%
Idaho Power Company	IDA	55.14%	54.25%	54.22%	53.15%	52.34%	53.82%
Florida Power & Light Company	NEE	60.24%	64.37%	59.93%	62.65%	61.41%	61.72%
Gulf Power Company	NEE	50.30%	59.73%	54.19%	58.68%	53.39%	55.26%
Pivotal Utility Holdings, Inc.	NEE						
Arizona Public Service Company	PNW	52.80%	54.36%	53.14%	54.59%	55.50%	54.08%
Public Service Company of New Mexico	PNM	45.42%	45.83%	46.26%	46.22%	45.54%	45.85%
Texas-New Mexico Power Company	PNM	52.74%	53.79%	56.70%	58.27%	59.35%	56.17%
Portland General Electric Company	POR	49.85%	50.19%	49.80%	49.82%	50.61%	50.05%
Alabama Power Company	SO	51.90%	48.74%	48.14%	48.07%	47.66%	48.90%
Atlanta Gas Light Company	SO		58.77%	54.62%	54.31%	54.46%	55.54%
Chattanooga Gas Company	SO		52.54%	52.46%	53.33%	52.34%	52.67%
Georgia Power Company	SO	56.12%	59.02%	50.06%	52.22%	51.70%	53.83%
Mississippi Power Company	SO	50.84%	50.35%	39.92%	49.90%	48.44%	47.89%
Northern Illinois Gas Company	SO		53.19%	53.66%	61.39%	62.31%	57.64%
Virginia Natural Gas, Inc.	SO		52.49%	54.18%	51.42%	50.91%	52.25%
Northern States Power Company - MN	XEL	52.20%	52.81%	52.38%	52.31%	53.26%	52.59%
Northern States Power Company - WI	XEL	54.23%	53.60%	53.36%	54.93%	54.27%	54.08%

**EQUITY RATIO - UTILITY OPERATING COMPANIES [2]**

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Company of Colorado	XEL	56.32%	56.31%	56.50%	56.32%	56.34%	56.36%
Southwestern Public Service Company	XEL	54.14%	54.17%	53.55%	53.93%	53.83%	53.92%
Empire District Electric Company	AQN	53.99%	52.25%	51.49%	51.51%	49.95%	51.84%
Empire District Gas Company	AQN	38.39%	37.28%	35.66%	33.12%	32.33%	35.35%
Liberty Utilities (CalPeco Electric) LLC	AQN		77.00%				77.00%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	54.12%	52.96%	51.47%	63.06%	61.29%	56.58%
Liberty Utilities (Granite State Electric) Corp.	AQN	77.03%	76.42%	75.52%	74.62%	73.78%	75.47%
Liberty Utilities (Midstates Natural Gas) Corp	AQN	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Liberty Utilities (New England Natural Gas Company) Corp	AQN	73.37%	70.67%	67.74%	59.76%	58.06%	65.92%
St. Lawrence Gas Company, Inc.	AQN		83.65%	82.81%	81.96%	84.74%	83.29%
New Mexico Gas Company, Inc.	EMA		70.77%	70.45%	69.81%	69.82%	70.21%
Peoples Gas System	EMA	61.29%	58.39%	60.09%	57.18%	57.07%	58.80%
Tampa Electric Company	EMA	55.30%	55.63%	57.40%	55.73%	53.12%	55.44%
Nova Scotia Power	EMA	35.17%	30.70%	30.85%	32.38%	31.51%	32.12%
Central Hudson Gas & Electric Corporation	FTS	50.84%	50.84%	51.15%	50.58%	51.44%	50.97%
ITC Interconnection LLC	FTS	59.21%	60.03%	60.60%	58.06%		59.48%
Tucson Electric Power Company	FTS	55.10%	52.80%	53.20%	51.58%	50.20%	52.58%
UNS Electric, Inc.	FTS	57.48%	55.84%	54.59%	53.62%	52.56%	54.82%
UNS Gas, Inc.	FTS						
Fortis Alberta	FTS	41.06%	39.86%	40.26%	41.42%	43.59%	41.24%
Fortis BC	FTS	51.75%	51.59%	51.40%	54.01%	53.20%	52.39%
Fortis BC Energy (Gas)	FTS	51.30%	51.64%	52.85%	54.15%	56.26%	53.24%
Newfoundland Power	FTS	48.08%	45.53%	45.55%	46.26%	45.59%	46.20%
Maritime Electric	FTS						

**Notes:**

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

**CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP**

Proxy Group Company	Ticker	LONG-TERM DEBT RATIO [1]					Average
		2019	2018	2017	2016	2015	
ALLETE, Inc.	ALE	40.45%	38.73%	39.85%	42.99%	44.05%	41.21%
Ameren Corporation	AEE	47.15%	46.87%	46.95%	47.01%	47.49%	47.10%
American Electric Power Company, Inc.	AEP	50.56%	50.80%	50.43%	51.71%	51.94%	51.09%
Avista Corporation	AVA	49.17%	50.11%	49.25%	49.07%	49.59%	49.44%
Duke Energy Corporation	DUK	47.44%	47.50%	47.45%	47.86%	44.75%	47.00%
Edison International	EIX	46.21%	48.66%	42.81%	41.80%	43.71%	44.64%
El Paso Electric Company	EE	51.02%	52.12%	50.05%	52.27%	50.14%	51.12%
Entergy Corporation	ETR	51.79%	51.15%	52.21%	51.81%	50.13%	51.42%
FirstEnergy Corporation	FE	43.68%	41.10%	43.03%	45.41%	48.66%	44.37%
Evergy, Inc.	EVRG	45.87%	45.07%	45.78%	44.92%	44.16%	45.16%
IDACORP, Inc.	IDA	44.86%	45.75%	45.78%	46.85%	47.66%	46.18%
NextEra Energy, Inc.	NEE	40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
Pinnacle West Capital Corporation	PNW	47.20%	45.64%	46.86%	45.41%	44.50%	45.92%
PNM Resources, Inc.	PNM	52.32%	51.87%	50.97%	50.77%	51.21%	51.43%
Portland General Electric Company	POR	50.15%	49.81%	50.20%	50.18%	49.39%	49.95%
Southern Company	SO	45.80%	45.28%	50.76%	48.87%	49.42%	48.03%
Xcel Energy Inc.	XEL	45.71%	45.52%	45.77%	45.78%	45.41%	45.64%
Algonquin Power & Utilities Corp	AQN	42.20%	41.08%	44.48%	43.85%	45.42%	43.41%
Emera Inc.	EMA	51.94%	51.56%	50.78%	51.34%	53.08%	51.74%
Fortis Inc.	FTS	50.12%	51.02%	50.50%	49.87%	49.14%	50.13%
MEAN		47.21%	46.78%	47.23%	47.27%	47.46%	47.19%
LOW		40.45%	36.05%	39.85%	37.71%	39.39%	38.87%
HIGH		52.32%	52.12%	52.21%	52.27%	53.08%	51.74%

**LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]**

Company Name	Ticker	2019	2018	2017	2016	2015	Average
ALLETE (Minnesota Power)	ALE	40.41%	38.61%	39.96%	43.08%	44.14%	41.24%
Superior Water, Light and Power Company	ALE	41.92%	43.14%	35.01%	38.88%	39.77%	39.74%
Ameren Illinois Company	AEE	46.63%	46.73%	46.15%	46.05%	46.04%	46.32%
Union Electric Company	AEE	47.64%	47.00%	47.58%	47.70%	48.47%	47.68%
AEP Texas Central Company	AEP				53.99%	56.37%	55.18%
AEP Texas North Company	AEP				56.71%	57.64%	57.18%
Appalachian Power Company	AEP	51.26%	50.49%	51.28%	53.11%	53.23%	51.87%
Indiana Michigan Power Company	AEP	53.26%	55.38%	53.67%	50.89%	47.35%	52.11%
Kentucky Power Company	AEP	52.66%	54.28%	56.48%	56.55%	56.74%	55.34%
Kingsport Power Company	AEP	45.38%	49.21%	53.47%	34.76%	40.30%	44.62%
Ohio Power Company	AEP	45.50%	42.20%	41.37%	43.49%	49.91%	44.49%
Public Service Company of Oklahoma	AEP	50.31%	50.84%	51.50%	51.53%	53.55%	51.54%
Southwestern Electric Power Company	AEP	51.20%	53.03%	51.48%	54.05%	50.41%	52.03%
Transource Maryland, LLC	AEP	59.82%	58.19%				59.01%
Transource Pennsylvania, LLC	AEP	59.85%	58.08%				58.97%
Wheeling Power Company	AEP	46.49%	45.38%	45.74%	45.88%	46.27%	45.95%
Avista Corporation	AVA	49.17%	50.11%	49.25%	49.07%	49.59%	49.44%
Duke Energy Carolinas, LLC	DUK	47.89%	48.22%	47.02%	47.19%	41.93%	46.45%
Duke Energy Florida, LLC	DUK	50.09%	49.96%	50.75%	49.17%	44.72%	48.94%
Duke Energy Indiana, LLC	DUK	47.16%	46.74%	48.06%	48.41%	49.73%	48.02%
Duke Energy Kentucky, Inc.	DUK	50.63%	48.05%	46.89%	45.26%	43.89%	46.94%
Duke Energy Ohio, Inc.	DUK	34.78%	31.91%	33.76%	33.61%	31.29%	33.07%
Duke Energy Progress, LLC	DUK	48.71%	49.00%	47.73%	48.42%	47.60%	48.29%
Piedmont Natural Gas Company, Inc.	DUK		50.68%	55.21%	61.28%	57.94%	56.28%
Southern California Edison Company	EIX	46.21%	48.66%	42.81%	41.80%	43.71%	44.64%
El Paso Electric Company	EE	51.02%	52.12%	50.05%	52.27%	50.14%	51.12%
Entergy Arkansas, LLC	ETR	52.10%	50.58%	53.73%	53.46%	54.35%	52.84%
Entergy Louisiana, LLC	ETR	52.53%	52.63%	52.57%	52.13%	48.87%	51.75%
Entergy Mississippi, LLC	ETR	51.40%	50.89%	51.72%	50.42%	49.92%	50.87%
Entergy New Orleans, LLC	ETR	50.74%	48.81%	46.84%	45.19%	39.99%	46.31%
Entergy Texas, Inc.	ETR	49.08%	46.54%	49.55%	50.44%	50.04%	49.13%
Cleveland Electric Illuminating Company	FE	44.83%	44.56%	44.73%	49.11%	54.90%	47.63%
Jersey Central Power & Light Company	FE	31.67%	30.54%	34.70%	40.79%	47.68%	37.08%
Metropolitan Edison Company	FE	52.00%	46.79%	47.67%	49.70%	51.57%	49.55%
Monongahela Power Company	FE	53.64%	51.13%	50.85%	50.85%	51.11%	51.52%
Ohio Edison Company	FE	33.23%	30.07%	35.09%	36.34%	36.42%	34.23%
Pennsylvania Electric Company	FE	49.63%	46.11%	47.94%	48.15%	52.30%	48.82%
Pennsylvania Power Company	FE	51.21%	50.97%	46.18%	47.94%	41.84%	47.63%
Potomac Edison Company	FE	45.69%	47.65%	48.41%	49.92%	48.41%	48.02%
Toledo Edison Company	FE	40.26%	39.57%	39.96%	38.02%	39.59%	39.48%
West Penn Power Company	FE	52.31%	46.50%	47.18%	47.38%	50.52%	48.78%
Great Plains Energy Incorporated	EVRG	49.68%	48.95%	49.85%	48.85%	49.20%	49.30%
Westar Energy (KPL)	EVRG	42.03%	40.92%	41.26%	40.32%	37.79%	40.46%
Idaho Power Company	IDA	44.86%	45.75%	45.78%	46.85%	47.66%	46.18%
Florida Power & Light Company	NEE	39.76%	35.63%	40.07%	37.35%	38.59%	38.28%
Gulf Power Company	NEE	49.70%	40.27%	45.81%	41.32%	46.61%	44.74%
Pivotal Utility Holdings, Inc.	NEE						
Arizona Public Service Company	PNW	47.20%	45.64%	46.86%	45.41%	44.50%	45.92%
Public Service Company of New Mexico	PNM	54.58%	54.17%	53.74%	53.78%	54.46%	54.15%
Texas-New Mexico Power Company	PNM	47.26%	46.21%	43.30%	41.73%	40.65%	43.83%
Portland General Electric Company	POR	50.15%	49.81%	50.20%	50.18%	49.39%	49.95%
Alabama Power Company	SO	48.10%	51.26%	51.86%	51.93%	52.34%	51.10%
Atlanta Gas Light Company	SO		41.23%	45.38%	45.69%	45.54%	44.46%
Chattanooga Gas Company	SO		47.46%	47.54%	46.67%	47.66%	47.33%
Georgia Power Company	SO	43.88%	40.98%	49.94%	47.78%	48.30%	46.17%
Mississippi Power Company	SO	49.16%	49.65%	60.08%	50.10%	51.56%	52.11%
Northern Illinois Gas Company	SO		46.81%	46.34%	38.61%	37.69%	42.36%
Virginia Natural Gas, Inc.	SO		47.51%	45.82%	48.58%	49.09%	47.75%
Northern States Power Company - MN	XEL	47.80%	47.19%	47.62%	47.69%	46.74%	47.41%
Northern States Power Company - WI	XEL	45.77%	46.40%	46.64%	45.07%	45.73%	45.92%

**LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]**

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Company of Colorado	XEL	43.68%	43.69%	43.50%	43.68%	43.66%	43.64%
Southwestern Public Service Company	XEL	45.86%	45.83%	46.45%	46.07%	46.17%	46.08%
Empire District Electric Company	AQN	46.01%	47.75%	48.51%	48.49%	50.05%	48.16%
Empire District Gas Company	AQN	61.61%	62.72%	64.34%	66.88%	67.67%	64.65%
Liberty Utilities (CalPeco Electric) LLC	AQN		23.00%				23.00%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	45.88%	47.04%	48.53%	36.94%	38.71%	43.42%
Liberty Utilities (Granite State Electric) Corp.	AQN	22.97%	23.58%	24.48%	25.38%	26.22%	24.53%
Liberty Utilities (Midstates Natural Gas) Corp	AQN	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Liberty Utilities (New England Natural Gas Company) Corp	AQN	26.63%	29.33%	32.26%	40.24%	41.94%	34.08%
St. Lawrence Gas Company, Inc.	AQN		16.35%	17.19%	18.04%	15.26%	16.71%
New Mexico Gas Company, Inc.	EMA		29.23%	29.55%	30.19%	30.18%	29.79%
Peoples Gas System	EMA	38.71%	41.61%	39.91%	42.82%	42.93%	41.20%
Tampa Electric Company	EMA	44.70%	44.37%	42.60%	44.27%	46.88%	44.56%
Nova Scotia Power	EMA	64.83%	69.30%	69.15%	67.62%	68.49%	67.88%
Central Hudson Gas & Electric Corporation	FTS	49.16%	49.16%	48.85%	49.42%	48.56%	49.03%
ITC Interconnection LLC	FTS	40.79%	39.97%	39.40%	41.94%		40.52%
Tucson Electric Power Company	FTS	44.90%	47.20%	46.80%	48.42%	49.80%	47.42%
UNS Electric, Inc.	FTS	42.52%	44.16%	45.41%	46.38%	47.44%	45.18%
UNS Gas, Inc.	FTS						
Fortis Alberta	FTS	58.94%	60.14%	59.74%	58.58%	56.41%	58.76%
Fortis BC	FTS	48.25%	48.41%	48.60%	45.99%	46.80%	47.61%
Fortis BC Energy (Gas)	FTS	48.70%	48.36%	47.15%	45.85%	43.74%	46.76%
Newfoundland Power	FTS	51.92%	54.47%	54.45%	53.74%	54.41%	53.80%
Maritime Electric	FTS						

**Notes:**

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

**CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP**

Proxy Group Company	Ticker	EQUITY RATIO [1]					Average
		2019	2018	2017	2016	2015	
Public Service Enterprise Group, Inc.	PEG	54.72%	54.24%	53.41%	52.74%	52.65%	53.55%
NextEra Energy, Inc.	NEE	59.37%	63.95%	59.41%	62.29%	60.61%	61.13%
Exelon Corporation	EXC	53.13%	53.31%	53.38%	52.99%	52.47%	53.06%
MEAN		55.74%	57.17%	55.40%	56.01%	55.24%	55.91%
LOW		53.13%	53.31%	53.38%	52.74%	52.47%	53.06%
HIGH		59.37%	63.95%	59.41%	62.29%	60.61%	61.13%

Company Name	Ticker	EQUITY RATIO - UTILITY OPERATING COMPANIES [2]					Average
		2019	2018	2017	2016	2015	
Public Service Electric and Gas Company	PEG	54.72%	54.24%	53.41%	52.74%	52.65%	53.55%
Florida Power & Light Company	NEE	60.24%	64.37%	59.93%	62.65%	61.41%	61.72%
Gulf Power Company	NEE	50.30%	59.73%	54.19%	58.68%	53.39%	55.26%
Pivotal Utility Holdings, Inc.	NEE						
Atlantic City Electric Company	EXC	49.29%	49.14%	49.19%	48.37%	47.04%	48.61%
Baltimore Gas and Electric Company	EXC	52.80%	53.67%	54.77%	52.54%	57.75%	54.31%
Commonwealth Edison Company	EXC	54.94%	55.06%	54.85%	54.52%	54.99%	54.87%
Delmarva Power & Light Company	EXC	50.12%	49.98%	50.38%	49.43%	49.05%	49.79%
PECO Energy Co.	EXC	53.62%	53.72%	53.54%	55.13%	53.80%	53.96%
Pepco Holdings LLC	EXC					48.56%	48.56%
Potomac Electric Power Company	EXC	50.16%	50.01%	49.89%	49.57%	49.00%	49.72%

Notes:

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

**CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP**

<b>LONG-TERM DEBT RATIO [1]</b>							
Proxy Group Company	Ticker	2019	2018	2017	2016	2015	Average
Public Service Enterprise Group, Inc.	PEG	45.28%	45.76%	46.59%	47.26%	47.35%	46.45%
NextEra Energy, Inc.	NEE	40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
Exelon Corporation	EXC	46.87%	46.69%	46.62%	47.01%	47.53%	46.94%
MEAN		44.26%	42.83%	44.60%	43.99%	44.76%	44.09%
LOW		40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
HIGH		46.87%	46.69%	46.62%	47.26%	47.53%	46.94%

**LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]**

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Electric and Gas Company	PEG	45.28%	45.76%	46.59%	47.26%	47.35%	46.45%
Florida Power & Light Company	NEE	39.76%	35.63%	40.07%	37.35%	38.59%	38.28%
Gulf Power Company	NEE	49.70%	40.27%	45.81%	41.32%	46.61%	44.74%
Pivotal Utility Holdings, Inc.	NEE						
Atlantic City Electric Company	EXC	50.71%	50.86%	50.81%	51.63%	52.96%	51.39%
Baltimore Gas and Electric Company	EXC	47.20%	46.33%	45.23%	47.46%	42.25%	45.69%
Commonwealth Edison Company	EXC	45.06%	44.94%	45.15%	45.48%	45.01%	45.13%
Delmarva Power & Light Company	EXC	49.88%	50.02%	49.62%	50.57%	50.95%	50.21%
PECO Energy Co.	EXC	46.38%	46.28%	46.46%	44.87%	46.20%	46.04%
Pepco Holdings LLC	EXC					51.44%	51.44%
Potomac Electric Power Company	EXC	49.84%	49.99%	50.11%	50.43%	51.00%	50.28%

Notes:

[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

**CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP**

Proxy Group Company	Ticker	COMMON EQUITY RATIO [1]					Average
		2015	2016	2017	2018	2019	
ALLETE, Inc.	ALE	53.70%	58.00%	59.00%	60.10%	61.40%	58.44%
Ameren Corporation	AEE	49.70%	51.30%	49.80%	48.80%	47.10%	49.34%
American Electric Power Company, Inc.	AEP	50.20%	50.00%	48.50%	46.80%	43.90%	47.88%
Avista Corporation	AVA	50.00%	48.80%	52.80%	49.50%	50.60%	50.34%
Duke Energy Corporation	DUK	51.40%	47.40%	46.00%	46.20%	44.10%	47.02%
Edison International	EIX	46.70%	49.20%	45.80%	38.30%	39.90%	43.98%
El Paso Electric Company	EE	47.30%	47.30%	48.80%	47.50%	47.60%	47.70%
Entergy Corporation	ETR	40.80%	35.50%	35.50%	35.90%	37.10%	36.96%
FirstEnergy Corporation	FE	39.30%	25.50%	15.70%	27.40%	26.20%	26.82%
Evergy, Inc.	EVRG	N/A	N/A	N/A	60.00%	49.40%	54.70%
IDACORP, Inc.	IDA	54.40%	55.20%	56.30%	56.40%	58.70%	56.20%
NextEra Energy, Inc.	NEE	45.80%	46.70%	47.30%	56.00%	49.60%	49.08%
Pinnacle West Capital Corporation	PNW	57.00%	54.40%	51.10%	53.00%	52.90%	53.68%
PNM Resources, Inc.	PNM	45.50%	44.00%	43.60%	38.60%	39.90%	42.32%
Portland General Electric Company	POR	52.20%	51.60%	49.90%	53.50%	48.70%	51.18%
Southern Company	SO	44.00%	35.70%	35.00%	37.60%	39.50%	38.36%
Xcel Energy Inc.	XEL	45.90%	43.70%	44.10%	43.60%	43.20%	44.10%
Algonquin Power & Utilities Corp [2]	AQN	45.55%	26.72%	39.58%	42.55%	44.26%	39.73%
Emera Inc.	EMA	52.83%	31.97%	35.04%	36.79%	38.51%	39.03%
Fortis Inc.	FTS	38.10%	36.20%	37.10%	37.20%	41.80%	38.08%
MEAN		47.91%	44.17%	44.26%	45.79%	45.22%	45.75%
LOW		38.10%	25.50%	15.70%	27.40%	26.20%	26.82%
HIGH		57.00%	58.00%	59.00%	60.10%	61.40%	58.44%

[1] Data per Value Line Investment Survey

[2] Calculated per Annual Reports, excludes preferred equity & non-controlling interests

**CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP**

Proxy Group Company	Ticker	LONG-TERM DEBT RATIO [1]					Average
		2015	2016	2017	2018	2019	
ALLETE, Inc.	ALE	46.30%	42.00%	41.00%	39.90%	38.60%	41.56%
Ameren Corporation	AEE	49.30%	47.70%	49.20%	50.30%	52.10%	49.72%
American Electric Power Company, Inc.	AEP	49.80%	50.00%	51.50%	53.20%	56.10%	52.12%
Avista Corporation	AVA	50.00%	51.20%	47.20%	50.50%	49.40%	49.66%
Duke Energy Corporation	DUK	48.60%	52.60%	54.00%	53.80%	54.00%	52.60%
Edison International	EIX	45.00%	41.80%	45.60%	53.60%	53.50%	47.90%
El Paso Electric Company	EE	52.70%	52.70%	51.20%	52.50%	52.40%	52.30%
Entergy Corporation	ETR	57.80%	63.60%	63.60%	63.20%	62.00%	62.04%
FirstEnergy Corporation	FE	60.70%	74.50%	84.30%	72.30%	73.80%	73.12%
Evergy, Inc.	EVRG	N/A	N/A	N/A	40.00%	50.60%	45.30%
IDACORP, Inc.	IDA	45.60%	44.80%	43.70%	43.60%	41.30%	43.80%
NextEra Energy, Inc.	NEE	54.20%	53.30%	52.70%	44.00%	50.40%	50.92%
Pinnacle West Capital Corporation	PNW	43.00%	45.60%	48.90%	47.00%	47.10%	46.32%
PNM Resources, Inc.	PNM	54.10%	55.70%	56.10%	61.10%	59.80%	57.36%
Portland General Electric Company	POR	47.80%	48.40%	50.10%	46.50%	51.30%	48.82%
Southern Company	SO	52.80%	61.50%	64.50%	62.00%	60.10%	60.18%
Xcel Energy Inc.	XEL	54.10%	56.30%	55.90%	56.40%	56.80%	55.90%
Algonquin Power & Utilities Corp [2]	AQN	39.35%	61.15%	48.12%	47.44%	47.15%	48.64%
Emera Inc.	EMA	47.17%	68.03%	64.96%	63.21%	61.49%	60.97%
Fortis Inc.	FTS	53.30%	59.30%	58.40%	58.80%	54.20%	56.80%
MEAN		50.09%	54.22%	54.26%	52.97%	53.61%	52.80%
LOW		39.35%	41.80%	41.00%	39.90%	38.60%	41.56%
HIGH		60.70%	74.50%	84.30%	72.30%	73.80%	73.12%

[1] Data per Value Line Investment Survey

[2] Calculated per Annual Reports

**CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP**

Proxy Group Company	Ticker	COMMON EQUITY RATIO [1]					Average
		2015	2016	2017	2018	2019	
Public Service Enterprise Group, Inc.	PEG	59.70%	54.70%	53.40%	52.20%	52.30%	54.46%
NextEra Energy, Inc.	NEE	45.80%	46.70%	47.30%	56.00%	49.60%	49.08%
Exelon Corporation	EXC	51.30%	44.50%	47.80%	47.20%	50.40%	48.24%
MEAN		52.27%	48.63%	49.50%	51.80%	50.77%	50.59%
LOW		45.80%	44.50%	47.30%	47.20%	49.60%	48.24%
HIGH		59.70%	54.70%	53.40%	56.00%	52.30%	54.46%

Notes:

[1] Data per Value Line Investment Survey

**CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP**

Proxy Group Company	Ticker	LONG-TERM DEBT RATIO [1]					Average
		2015	2016	2017	2018	2019	
Public Service Enterprise Group, Inc.	PEG	40.30%	45.30%	46.60%	47.80%	47.70%	45.54%
NextEra Energy, Inc.	NEE	54.20%	53.30%	52.70%	44.00%	50.40%	50.92%
Exelon Corporation	EXC	48.30%	55.50%	52.20%	52.80%	49.60%	51.68%
MEAN		47.60%	51.37%	50.50%	48.20%	49.23%	49.38%
LOW		40.30%	45.30%	46.60%	44.00%	47.70%	45.54%
HIGH		54.20%	55.50%	52.70%	52.80%	50.40%	51.68%

Notes:

[1] Data per Value Line Investment Survey

RISK ASSESSMENT: Concentric Proxy Group

	[1]	[2]	[3]	[4]			
Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year
ALLETE, Inc. Ameren Corporation	ALE	Minnesota Power	Electric	BBB	Minnesota	Highly Credit Supportive (strong/adequate)	Fully Forecast
	AEE	Ameren Illinois Co.	Electric	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Historical
	AEE	Ameren Illinois Co.	Gas	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Fully Forecast
American Electric Power Company, Inc.	AEE	Union Electric Co.	Electric	BBB+	Missouri	Very Credit Supportive (strong/adequate)	Historical
	AEE	Union Electric Co.	Gas	BBB+	Missouri	Very Credit Supportive (strong/adequate)	Historical
	AEP	Southwestern Electric Power Co.	Electric	A-	Arkansas	Highly Credit Supportive (strong/adequate)	Partially Forecast
	AEP	Indiana Michigan Power Co.	Electric	A-	Indiana	Highly Credit Supportive (strong/adequate)	Fully Forecast
	AEP	Kentucky Power Co.	Electric	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	AEP	Southwestern Electric Power Co.	Electric	A-	Louisiana	Highly Credit Supportive (strong/adequate)	Historical
	AEP	Indiana Michigan Power Co.	Electric	A-	Michigan	Most Credit Supportive (strong)	Fully Forecast
	AEP	Ohio Power Co.	Electric	A-	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	AEP	Public Service Co. of Oklahoma	Electric	A-	Oklahoma	More Credit Supportive (strong/adequate)	Historical
	AEP	Kingsport Power Co.	Electric	A-	Tennessee	Highly Credit Supportive (strong/adequate)	Fully Forecast
	AEP	AEP Texas	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	AEP	Southwestern Electric Power Co.	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	Avista Corporation	AEP	Appalachian Power Co.	Electric	A-	Virginia	Highly Credit Supportive (strong/adequate)
AEP		Appalachian Power Co.	Electric	A-	West Virginia	Very Credit Supportive (strong/adequate)	Historical
AVA		Alaska Electric Light & Power	Electric	BBB	Alaska	More Credit Supportive (strong/adequate)	Historical
AVA		Avista Corp.	Electric	BBB	Idaho	Very Credit Supportive (strong/adequate)	Historical
AVA		Avista Corp.	Gas	BBB	Idaho	Very Credit Supportive (strong/adequate)	Historical
Duke Energy Corporation	AVA	Avista Corp.	Gas	BBB	Oregon	Highly Credit Supportive (strong/adequate)	Fully Forecast
	AVA	Avista Corp.	Electric	BBB	Washington	More Credit Supportive (strong/adequate)	Historical
	AVA	Avista Corp.	Gas	BBB	Washington	More Credit Supportive (strong/adequate)	Historical
	DUK	Duke Energy Florida LLC	Electric	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Indiana LLC	Electric	A-	Indiana	Highly Credit Supportive (strong/adequate)	Historical
	DUK	Duke Energy Kentucky Inc.	Electric	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Kentucky Inc.	Gas	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Carolinas LLC	Electric	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Duke Energy Progress LLC	Electric	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Duke Energy Ohio Inc.	Electric	A-	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	DUK	Duke Energy Ohio Inc.	Gas	A-	Ohio [6]	Very Credit Supportive (strong/adequate)	Partially Forecast
	DUK	Duke Energy Progress LLC	Electric	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical
DUK	Duke Energy Carolinas LLC	Electric	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical	
DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical	
	DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	Tennessee	Highly Credit Supportive (strong/adequate)	Fully Forecast

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Electric fuel/gas commodity/purch. power	[5] Conserv. program expense	[5] Full Decoupling	[5] Partial Decoupling	[5] Renewables expense	[5] Environmental compliance	[5] Generation capacity	[5] Generic infrastructure	[5] Transmission expense	[5] Other	
ALLETE, Inc.	ALE	Minnesota Power	✓	✓			✓	✓			✓		
Ameren Corporation	AEE	Ameren Illinois Co.	NA	✓			✓	✓			✓	✓	
	AEE	Ameren Illinois Co.	✓	✓		✓		✓		✓		✓	
	AEE	Union Electric Co.	✓	✓		✓	✓	✓		✓	✓	✓	
	AEE	Union Electric Co.	✓			✓				✓		✓	
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	✓	✓		✓		✓	✓		✓	✓	
	AEP	Indiana Michigan Power Co.	✓	✓		✓	✓	✓		✓	✓	✓	
	AEP	Kentucky Power Co.	✓	✓		✓	✓	✓				✓	
	AEP	Southwestern Electric Power Co.	✓	✓		✓		✓				✓	
	AEP	Indiana Michigan Power Co.	✓	✓			✓					✓	
	AEP	Ohio Power Co.	NA	✓		✓	✓			✓	✓	✓	
	AEP	Public Service Co. of Oklahoma	✓	✓		✓	✓			✓	✓	✓	
	AEP	Kingsport Power Co.	✓										✓
	AEP	AEP Texas	NA	✓							✓	✓	
	AEP	Southwestern Electric Power Co.	✓	✓						✓	✓		✓
	AEP	Appalachian Power Co.	✓	✓			✓		✓		✓		✓
	AEP	Appalachian Power Co.	✓	✓			✓						✓
Avista Corporation	AVA	Alaska Electric Light & Power	✓										
	AVA	Avista Corp.	✓	✓	✓								
	AVA	Avista Corp.	✓	✓	✓								
	AVA	Avista Corp.	✓	✓	✓								
	AVA	Avista Corp.	✓	✓		✓	✓						
Duke Energy Corporation	DUK	Duke Energy Florida LLC	✓	✓				✓	✓			✓	
	DUK	Duke Energy Indiana LLC	✓	✓		✓	✓	✓	✓		✓	✓	
	DUK	Duke Energy Kentucky Inc.	✓	✓		✓	✓	✓				✓	
	DUK	Duke Energy Kentucky Inc.	✓	✓		✓		✓				✓	
	DUK	Duke Energy Carolinas LLC	✓	✓			✓	✓					
	DUK	Duke Energy Progress LLC	✓	✓			✓	✓					
	DUK	Piedmont Natural Gas Co. Inc.	✓	✓	✓					✓			
	DUK	Duke Energy Ohio Inc.	NA	✓		✓	✓			✓	✓	✓	✓
	DUK	Duke Energy Ohio Inc.	✓		✓					✓			✓
	DUK	Duke Energy Progress LLC	✓	✓				✓					
	DUK	Duke Energy Carolinas LLC	✓	✓				✓					
	DUK	Piedmont Natural Gas Co. Inc.	✓	✓		✓							
	DUK	Piedmont Natural Gas Co. Inc.	✓			✓					✓		✓

RISK ASSESSMENT: Concentric Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
ALLETE, Inc. Ameren Corporation	ALE	Minnesota Power	
	AEE	Ameren Illinois Co.	Certain hazardous materials litigation, bad-debt costs, and taxes recoverable
	AEE	Ameren Illinois Co.	Certain hazardous materials litigation, bad-debt costs, and taxes recoverable
American Electric Power Company, Inc.	AEE	Union Electric Co.	Renewable energy standard compliance costs, emission allowance costs, government-mandated investments, and certain taxes recoverable
	AEE	Union Electric Co.	Renewable energy standard compliance costs, emission allowance costs, government-mandated investments, and certain taxes recoverable
	AEP	Southwestern Electric Power Co.	Certain taxes recoverable
	AEP	Indiana Michigan Power Co.	Regulatory mechanisms allow sharing of off system sales margins
	AEP	Kentucky Power Co.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	AEP	Southwestern Electric Power Co.	Regulatory mechanisms allow sharing of off system sales margins; Economic development riders
	AEP	Indiana Michigan Power Co.	Economic development rider
	AEP	Ohio Power Co.	Certain bad-debt costs and taxes recoverable
	AEP	Public Service Co. of Oklahoma	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	AEP	Kingsport Power Co.	
	AEP	AEP Texas	
	Avista Corporation	AEP	Southwestern Electric Power Co.
AEP		Appalachian Power Co.	Certain taxes recoverable
AEP		Appalachian Power Co.	Certain taxes recoverable
AVA		Alaska Electric Light & Power	
AVA		Avista Corp.	
Duke Energy Corporation	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	DUK	Duke Energy Florida LLC	Certain taxes and storm costs recoverable
	DUK	Duke Energy Indiana LLC	Regulatory mechanisms allow sharing of off system sales margins
	DUK	Duke Energy Kentucky Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	DUK	Duke Energy Kentucky Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	DUK	Duke Energy Carolinas LLC	
	DUK	Duke Energy Progress LLC	
	DUK	Piedmont Natural Gas Co. Inc.	
	DUK	Duke Energy Ohio Inc.	Incremental vegetation management costs, certain taxes and bad-debt costs recoverable
	DUK	Duke Energy Ohio Inc.	Certain taxes and bad-debt costs recoverable
DUK	Duke Energy Progress LLC		
DUK	Duke Energy Carolinas LLC		
DUK	Piedmont Natural Gas Co. Inc.		
DUK	Piedmont Natural Gas Co. Inc.	Riders related to capacity management and release, off-system sales, and capacity assignment; Margin losses from bypassable customers recoverable	

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year
Edison International El Paso	EIX	Southern California Edison Co.	Electric	BBB	California	More Credit Supportive (strong/adequate)	Fully Forecast
	EE	El Paso Electric Co.	Electric	BBB	New Mexico	Credit Supportive (adequate)	Historical
	EE	El Paso Electric Co.	Electric	BBB	Texas	Very Credit Supportive (strong/adequate)	Historical
Entergy Corporation	ETR	Entergy Arkansas LLC	Electric	A-	Arkansas	Highly Credit Supportive (strong/adequate)	Fully Forecast
	ETR	Entergy New Orleans LLC	Electric	BBB+	Louisiana NOCC	Highly Credit Supportive (strong/adequate)	Historical
	ETR	Entergy New Orleans LLC	Gas	BBB+	Louisiana NOCC	Highly Credit Supportive (strong/adequate)	Historical
	ETR	Entergy Louisiana LLC	Electric	A-	Louisiana PSC	Highly Credit Supportive (strong/adequate)	Historical
	ETR	Entergy Louisiana LLC	Gas	A-	Louisiana PSC	Highly Credit Supportive (strong/adequate)	Historical
	ETR	Entergy Mississippi	Electric	A-	Mississippi	Credit Supportive (adequate)	Fully Forecast
	ETR	Entergy Texas Inc.	Electric	BBB+	Texas	Very Credit Supportive (strong/adequate)	Historical
FirstEnergy Corp.	FE	Potomac Edison Co.	Electric	BBB	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	FE	Jersey Central Power & Light Co.	Electric	BBB	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	FE	Cleveland Electric Illuminating	Electric	BBB	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	FE	Metropolitan Edison Co	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
	FE	Pennsylvania Electric Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
	FE	Pennsylvania Power Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
	FE	West Penn Power Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
	FE	Monongahela Power Co.	Electric	BBB	West Virginia	Very Credit Supportive (strong/adequate)	Historical
	FE	Potomac Edison Co.	Electric	BBB	West Virginia	Very Credit Supportive (strong/adequate)	Historical
	Eversys, Inc.	EVRG	Eversys Kansas Central Inc.	Electric	A-	Kansas	Highly Credit Supportive (strong/adequate)
EVRG		Eversys Kansas South Inc.	Electric	A-	Kansas	Highly Credit Supportive (strong/adequate)	Historical
EVRG		Eversys Metro Inc.	Electric	A	Kansas	Highly Credit Supportive (strong/adequate)	Historical
EVRG		Eversys Metro Inc.	Electric	A	Missouri	Very Credit Supportive (strong/adequate)	Historical
EVRG		Eversys Missouri West Inc.	Electric	A-	Missouri	Very Credit Supportive (strong/adequate)	Historical
IDACORP, Inc.	IDA	Idaho Power Co.	Electric	BBB	Idaho	Very Credit Supportive (strong/adequate)	Partially Forecast
	IDA	Idaho Power Co.	Electric	BBB	Oregon	Highly Credit Supportive (strong/adequate)	Partially Forecast
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Gulf Power CO.	Electric	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Pivotal Utility Holdings Inc.	Gas	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Lone Star Transmission LLC	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
Pinnacle West Capital Corporation PNM Resources, Inc.	PNW	Arizona Public Service Co.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	PNM	Public Service Co. of New Mexico	Electric	BBB	New Mexico	Credit Supportive (adequate)	Fully Forecast
Portland General Electric Company Southern Company	PNM	Texas-New Mexico Power	Electric	BBB+	Texas	Very Credit Supportive (strong/adequate)	Historical
	POR	Portland General Electric Co.	Electric	BBB+	Oregon	Highly Credit Supportive (strong/adequate)	Fully Forecast
	SO	Alabama Power Co.	Electric	A	Alabama	Most Credit Supportive (strong)	Fully Forecast
	SO	Georgia Power Co.	Electric	A-	Georgia	Highly Credit Supportive (strong/adequate)	Fully Forecast
	SO	Atlanta Gas Light Co.	Gas	A-	Georgia [6]	Highly Credit Supportive (strong/adequate)	Fully Forecast
	SO	Northern Illinois Gas Co.	Gas	A	Illinois	Very Credit Supportive (strong/adequate)	Fully Forecast
	SO	Mississippi Power Co.	Electric	A-	Mississippi	Credit Supportive (adequate)	Fully Forecast
Xcel Energy Inc.	SO	Chattanooga Gas Co.	Gas	A-	Tennessee	Highly Credit Supportive (strong/adequate)	Fully Forecast
	SO	Virginia Natural Gas	Gas	A-	Virginia	Highly Credit Supportive (strong/adequate)	Historical
	XEL	Public Service Co. of Colorado	Electric	A-	Colorado	Most Credit Supportive (strong)	Historical
	XEL	Public Service Co. of Colorado	Gas	A-	Colorado	Most Credit Supportive (strong)	Historical
	XEL	Northern States Power Co - Minnesota	Electric	A-	Minnesota	Highly Credit Supportive (strong/adequate)	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Gas	A-	Minnesota	Highly Credit Supportive (strong/adequate)	Fully Forecast
	XEL	Southwestern Public Service Co.	Electric	A-	New Mexico	Credit Supportive (adequate)	Historical
	XEL	Northern States Power Co - Minnesota	Electric	A-	North Dakota	Highly Credit Supportive (strong/adequate)	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Gas	A-	North Dakota [6]	Highly Credit Supportive (strong/adequate)	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Electric	A-	South Dakota	Very Credit Supportive (strong/adequate)	Historical
	XEL	Southwestern Public Service Co.	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	XEL	Northern States Power Co - Wisconsin	Electric	A-	Wisconsin	Most Credit Supportive (strong)	Fully Forecast
	XEL	Northern States Power Co - Wisconsin	Gas	A-	Wisconsin	Most Credit Supportive (strong)	Fully Forecast



RISK ASSESSMENT: Concentric Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
Edison International El Paso	EIX	Southern California Edison Co.	All large electric utilities in California now impose a non-bypassable charge on ratepayers to establish a \$21 billion wildfire insurance fund
	EE	El Paso Electric Co.	Certain taxes and franchise fees recoverable
	EE	El Paso Electric Co.	Riders related to lost revenue associated with discounted service to military bases
Entergy Corporation	ETR	Entergy Arkansas LLC	Storm recovery rider related to securitization bond charges; Certain taxes and franchise fees recoverable
	ETR	Entergy New Orleans LLC	Storm reserve rider
	ETR	Entergy New Orleans LLC	Storm reserve rider
	ETR	Entergy Louisiana LLC	Economic development rider
	ETR	Entergy Louisiana LLC	
	ETR	Entergy Mississippi	Riders for ad valorem tax adjustments and storm reserves
	ETR	Entergy Texas Inc.	Rider for ad valorem tax adjustments
FirstEnergy Corp.	FE	Potomac Edison Co.	Certain taxes and fees recoverable
			Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
	FE	Jersey Central Power & Light Co.	Certain taxes and fees and uncollectible expense recoverable
	FE	Cleveland Electric Illuminating	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Metropolitan Edison Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Pennsylvania Electric Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Pennsylvania Power Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	West Penn Power Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Monongahela Power Co.	Certain taxes and fees recoverable
	FE	Potomac Edison Co.	Certain taxes and fees recoverable
Eversource, Inc.	EVRG	Eversource Kansas Central Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Eversource Kansas South Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Eversource Metro Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Eversource Metro Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Eversource Missouri West Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
IDACORP, Inc.	IDA	Idaho Power Co.	
	IDA	Idaho Power Co.	
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Gulf Power CO.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Pivotal Utility Holdings Inc.	Certain taxes and fees recoverable
	NEE	Lone Star Transmission LLC	
Pinnacle West Capital Corporation PNM Resources, Inc.	PNW	Arizona Public Service Co.	Franchise fees recoverable via adjustable line item on monthly bills
	PNM	Public Service Co. of New Mexico	Certain taxes and fees recoverable
Portland General Electric Company Southern Company	PNM	Texas-New Mexico Power	Adjustment clause reflects changes in municipal franchise fees
	POR	Portland General Electric Co.	
	SO	Alabama Power Co.	Adjustment provisions reflects changes in income, general, and local taxes
	SO	Georgia Power Co.	
	SO	Atlanta Gas Light Co.	
	SO	Northern Illinois Gas Co.	Riders to recover certain bad-debt costs, taxes and franchise fees
	SO	Mississippi Power Co.	Ad valorem tax adjustment rider
			Riders related to capacity management and release, off-system sales, and capacity assignment;
			Riders allow sharing of gross profit margin reduction associated with negotiated contracts that bypass distribution system
Xcel Energy Inc.	SO	Chattanooga Gas Co.	
	SO	Virginia Natural Gas	
	XEL	Public Service Co. of Colorado	Sharing of customer margins from generation-based short-term energy trading and proprietary trading
	XEL	Public Service Co. of Colorado	
	XEL	Northern States Power Co - Minnesota	
	XEL	Northern States Power Co - Minnesota	
	XEL	Southwestern Public Service Co.	Certain taxes and fees recoverable
	XEL	Northern States Power Co - Minnesota	Sharing of non-asset-based wholesale power margins
	XEL	Northern States Power Co - Minnesota	
	XEL	Northern States Power Co - Minnesota	Sharing of wholesale power margins
XEL	Southwestern Public Service Co.	Rider for lost revenue associated with discounted sales to state universities	
XEL	Northern States Power Co - Wisconsin	Certain taxes and fees recoverable	
XEL	Northern States Power Co - Wisconsin	Certain taxes and fees recoverable	

RISK ASSESSMENT: Concentric Proxy Group

	[1]	[2]	[3]	[4]			
Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	Gas	BBB	Georgia	Highly credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	Gas	BBB	Illinois	Very credit supportive (strong/adequate)	Fully Forecast
	AQN	Empire District Electric Co.	Electric	BBB	Kansas	Highly credit supportive (strong/adequate)	Historical
	AQN	Liberty Utilities (NE Nat Gas)	Gas	BBB	Massachusetts	Highly credit supportive (strong/adequate)	Historical
	AQN	Empire District Electric Co.	Electric	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Empire District Gas Co.	Gas	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities (Midstates)	Gas	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities EnergyNorth	Gas	BBB	New Hampshire	Highly credit supportive (strong/adequate)	Historical
	AQN	Liberty Utilities Granite St	Electric	BBB	New Hampshire	Highly credit supportive (strong/adequate)	Historical
	AQN	Enbridge Gas New Brunswick	Gas	BBB	New Brunswick	Not ranked	Fully Forecast
Emera Incorporated	EMA	Tampa Electric Co.	Electric	BBB+	Florida	Most Credit Supportive (strong)	Fully Forecast
	EMA	New Mexico Gas Co.	Gas	BBB	New Mexico	Credit Supportive (adequate)	Historical
	EMA	Nova Scotia Power Inc.	Electric	BBB+	Nova Scotia	Most Credit Supportive (strong)	Fully Forecast
Fortis Inc.	FTS	Central Hudson Gas & Electric	Electric	A-	New York	Very Credit Supportive (strong/adequate)	Fully Forecast
	FTS	Central Hudson Gas & Electric	Gas	A-	New York	Very Credit Supportive (strong/adequate)	Fully Forecast
	FTS	Tucson Electric Power Co.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	UNS Electric Inc.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	UNS Gas Inc.	Gas	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	FortisAlberta Inc	Electric	A-	Alberta	Most Credit Supportive (strong)	Historical
	FTS	FortisBC	Electric	A-	British Columbia	Most Credit Supportive (strong)	Fully Forecast
	FTS	FortisBC Energy	Gas	A-	British Columbia	Most Credit Supportive (strong)	Fully Forecast
	FTS	Newfoundland Power Inc	Electric	A-	Newfoundland & Labrador	Highly Credit Supportive (strong/adequate)	Fully Forecast
	FTS	Maritime Electric Company Ltd.	Electric	BBB+	Prince Edward Island	Credit Supportive (adequate)	Fully Forecast
Proxy Group Results				Average BBB+	Total 111	Average Very Credit Supportive (strong/adequate)	Fully Forecast = 41% Partially Forecast = 12% Historical = 48%

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Electric fuel/gas commodity/purch. power	[5] Conserv. program expense	[5] Full Decoupling	[5] Partial Decoupling	[5] Renewables expense	[5] Environmental compliance	[5] Generation capacity	[5] Generic infrastructure	[5] Transmission expense	[5] Other	
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	✓		✓								
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	✓	✓		✓						✓	
	AQN	Empire District Electric Co.	✓	✓				✓			✓	✓	
	AQN	Liberty Utilities (NE Nat Gas)	✓	✓	✓			✓		✓		✓	
	AQN	Empire District Electric Co.	✓					✓			✓	✓	
	AQN	Empire District Gas Co.	✓									✓	
	AQN	Liberty Utilities (Midstates)	✓			✓					✓	✓	
	AQN	Liberty Utilities EnergyNorth	✓		✓						✓		✓
	AQN	Liberty Utilities Granite St	NA			✓					✓		
	AQN	Enbridge Gas New Brunswick	NA								✓		✓
Emera Incorporated	EMA	Tampa Electric Co.	✓	✓				✓	✓			✓	
	EMA	New Mexico Gas Co.	✓	✓								✓	
	EMA	Nova Scotia Power Inc.	✓	✓		✓			✓	✓			
Fortis Inc.	FTS	Central Hudson Gas & Electric	NA		✓		✓					✓	
	FTS	Central Hudson Gas & Electric	✓		✓			✓		✓		✓	
	FTS	Tucson Electric Power Co.	✓	✓		✓	✓	✓				✓	
	FTS	UNS Electric Inc.	✓	✓		✓	✓				✓	✓	
	FTS	UNS Gas Inc.	✓			✓						✓	
	FTS	FortisAlberta Inc	NA								✓	✓	
	FTS	FortisBC	✓	✓	✓						✓	✓	
	FTS	FortisBC Energy	✓	✓	✓						✓	✓	
	FTS	Newfoundland Power Inc	✓	✓		✓			✓	✓		✓	
	FTS	Maritime Electric Company Ltd.	✓	✓		✓			✓	✓		✓	
Proxy Group Results			Adjustment Clauses Count and Percentage of Total Proxy Group										
			111	91	28	54	46	53	33	66	45	82	
			100%	82%	25%	49%	41%	48%	30%	59%	41%	74%	

RISK ASSESSMENT: Concentric Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	Bad-debt costs recovered via riders; certain taxes and franchise fees recovered via other Abbreviated rate cases allowed; off-system sales margins, recover variations in certain taxes and franchise fees Pension and post-employment benefits recoverable Off-system sales margins flow through; certain taxes and franchise fees recoverable Off-system sales margins flow through; certain taxes and franchise fees recoverable Certain taxes and franchise fees recoverable Regulatory deferral account for system buildout, earnings sharing, franchise fees, development O&M capitalized costs, intangible software, carbon tax pass through Franchise fees, gross receipts taxes, recoverable via line items on customer bills. Storm cost recovery. Certain local taxes and franchise fees recoverable
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	
	AQN	Empire District Electric Co.	
	AQN	Liberty Utilities (NE Nat Gas)	
	AQN	Empire District Electric Co.	
	AQN	Empire District Gas Co.	
	AQN	Liberty Utilities (Midstates)	
	AQN	Liberty Utilities EnergyNorth	
Emera Incorporated	AQN	Liberty Utilities Granite St	
	AQN	Enbridge Gas New Brunswick	
	EMA	Tampa Electric Co.	
Fortis Inc.	EMA	New Mexico Gas Co.	
	EMA	Nova Scotia Power Inc.	
	FTS	Central Hudson Gas & Electric	
	FTS	Central Hudson Gas & Electric	
	FTS	Tucson Electric Power Co.	
	FTS	UNS Electric Inc.	
	FTS	UNS Gas Inc.	
	FTS	FortisAlberta Inc	
	FTS	FortisBC	
	FTS	FortisBC Energy	
FTS	Newfoundland Power Inc		
FTS	Maritime Electric Company Ltd.		

Proxy Group Results

**RISK ASSESSMENT: Concentric Proxy Group**

				[1]	[2]	[3]	[4]
Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year

Notes:

[1] Source: S&P Global Market Intelligence, S&P Long-Term Issuer Rating. If the operating subsidiary is not rated by S&P, then this column reflects the parent company's Long-Term Issuer Rating.

[2] Source: S&P Global Market Intelligence

[3] S&P Global Ratings, Ratings Direct, U.S. And Canadian Regulatory Jurisdiction Updates And Insights: (November 2019)

[4] Source: Source: Regulatory Research Associates; The Test Year refers to the State Commissions' standard practice, regulatory filings and orders, annual reports, annual information forms, when not covered by SNL

[5] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.

[6] Operations classified as full revenue decoupling since the company operates under a straight fixed-variable rate design.

**RISK ASSESSMENT: Moody's Proxy Group**

				[1]	[2]	[3]	[4]
Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year
Public Service Enterprise Group, Inc.	PEG	Public Severice Electric & Gas Co.	Electric	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	PEG	Public Severice Electric & Gas Co.	Gas	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Gulf Power CO.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Pivotal Utility Holdings Inc.	Gas	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Lone Star Transmission LLC	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
Exelon Corporation	EXC	Delmarva Power & Light Co.	Electric	A-	Delaware	Very Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Delmarva Power & Light Co.	Gas	A-	Delaware	Very Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Potomac Electric Power Co.	Electric	A-	District of Columbia	More Credit Supportive (strong/adequate)	Historical
	EXC	Commonwealth Edison Co.	Electric	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Historical
	EXC	Baltimore Gas & Electric Co.	Electric	A	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Baltimore Gas & Electric Co.	Gas	A	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Delmarva Power & Light Co.	Electric	A-	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Potomac Electric Power Co.	Electric	A-	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Atlantic City Electric Co.	Electric	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	PECO Energy Co.	Electric	BBB+	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
EXC	PECO Energy Co.	Gas	BBB+	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast	
Proxy Group Results				Average A-	Total 17	Average Very Credit Supportive (strong/adequate)	Fully Forecast = 29% Partially Forecast = 53% Historical = 18%

RISK ASSESSMENT: Moody's Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Electric fuel/gas commodity/purch. power	[5] Conserv. program expense	[5] Full Decoupling	[5] Partial Decoupling	[5] Renewables expense	[5] Environmental compliance	[5] Generation capacity	[5] Generic infrastructure	[5] Transmission expense	[5] Other	
Public Service Enterprise Group, Inc.	PEG	Public Service Electric & Gas Co.	NA	✓			✓			✓		✓	
	PEG	Public Service Electric & Gas Co.	✓	✓		✓		✓		✓		✓	
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	✓	✓				✓	✓			✓	
	NEE	Gulf Power CO.	✓	✓				✓	✓			✓	
	NEE	Pivotal Utility Holdings Inc.	✓	✓				✓		✓		✓	
Exelon Corporation	NEE	Lone Star Transmission LLC	NA							✓		✓	
	EXC	Delmarva Power & Light Co.	NA							✓	✓	✓	
	EXC	Delmarva Power & Light Co.	✓					✓		✓		✓	
	EXC	Potomac Electric Power Co.	NA			✓	✓			✓		✓	
	EXC	Commonwealth Edison Co.	NA	✓			✓	✓		✓	✓	✓	
	EXC	Baltimore Gas & Electric Co.	NA	✓	✓							✓	
	EXC	Baltimore Gas & Electric Co.	✓	✓	✓					✓		✓	
	EXC	Delmarva Power & Light Co.	NA	✓	✓								✓
	EXC	Potomac Electric Power Co.	NA	✓	✓								✓
	EXC	Atlantic City Electric Co.	NA	✓			✓				✓		✓
	EXC	PECO Energy Co.	NA	✓							✓		✓
EXC	PECO Energy Co.	✓	✓							✓		✓	
Proxy Group Results			Adjustment Clauses Count and Percentage of Total Proxy Group										
			17	13	4	2	4	6	2	12	2	15	
			100%	76%	24%	12%	24%	35%	12%	71%	12%	88%	

RISK ASSESSMENT: Moody's Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
Public Service Enterprise Group, Inc.	PEG	Public Service Electric & Gas Co.	Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
	PEG	Public Service Electric & Gas Co.	Certain taxes and fees recoverable
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Gulf Power CO.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Pivotal Utility Holdings Inc.	Certain taxes and fees recoverable
Exelon Corporation	NEE	Lone Star Transmission LLC	Certain taxes and fees recoverable
	EXC	Delmarva Power & Light Co.	Relocation costs of ariel and underground facilities required by government agency projects recoverable
	EXC	Delmarva Power & Light Co.	Relocation costs of ariel and underground facilities required by government agency projects recoverable
	EXC	Potomac Electric Power Co.	Certain taxes and fees recoverable
	EXC	Commonwealth Edison Co.	Certain taxes, fees, and bad-debt costs recoverable
	EXC	Baltimore Gas & Electric Co.	Certain taxes and fees recoverable
	EXC	Baltimore Gas & Electric Co.	Certain taxes and fees recoverable
	EXC	Delmarva Power & Light Co.	Certain taxes and fees recoverable
	EXC	Potomac Electric Power Co.	Certain taxes and fees recoverable
	EXC	Atlantic City Electric Co.	Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
EXC	PECO Energy Co.	Certain taxes, fees, and nuclear decommissioning costs recoverable	
EXC	PECO Energy Co.	Certain taxes and fees recoverable	

Proxy Group Results

**RISK ASSESSMENT: Moody's Proxy Group**

				[1]	[2]	[3]	[4]
Proxy Group Company	Ticker	Operating Subsidiary	Type	Credit Rating	Jurisdiction	S&P Regulatory Assessment	Test Year

**Notes:**

[1] Source: S&P Global Market Intelligence, S&P Long-Term Issuer Rating. If the operating subsidiary is not rated by S&P, then this column reflects the parent company's Long-Term Issuer Rating.

[2] Source: S&P Global Market Intelligence

[3] S&P Global Ratings, Ratings Direct, U.S. And Canadian Regulatory Jurisdiction Updates And Insights: (November 2019)

[4] Source: Source: Regulatory Research Associates; The Test Year refers to the State Commissions' standard practice, regulatory filings and orders, annual reports, annual information forms, when not covered by SNL

[5] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.

[6] Operations classified as full revenue decoupling since the company operates under a straight fixed-variable rate design.

**CCC Interrogatory #026**

**Interrogatory**

**Reference:**

**Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 49, 101-102**

Question(s):

- a) Please provide the credit metrics analysis shown in Exhibit 1 to the Report in excel format.
- b) Please confirm that the only change made between the two analyses (Exhibit 1 to the Report) is to the equity portion of the capital structure (and all other non-calculated costs in the table remain unchanged).
- c) Please provide the same information as is provided in Exhibit 1 for the period 2017-2026 using the OEB-approved equity ratio over that period in excel format.

**Response**

*This response was prepared by Concentric Energy Advisors (“Concentric”)*

- a) Please see the provided workpaper “CEA Exhibits - Credit Metric Analysis Workpaper” for the requested file. For convenience, we have additionally provided it as Attachment 1 to this interrogatory response.
- b) Confirmed.
- c) See Attachment 2.

**CCC Interrogatory #031**

**Interrogatory**

**Reference:**

**Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 67, 107-109**

Question(s):

- a) Please confirm that the following table is correct (with the addition of the most credit supportive peer group) or otherwise correct the table. If available, please also add the actual equity ratio (5-year average) for the most credit supportive peer group.

	<i>Concentric Proxy Group</i>		<i>Nuclear Group</i>		<i>Hydro Group Group</i>		<i>Most Credit Supportive</i>	
<i>Peer Group Equity Ratios</i>	<i>Actual</i>	<i>Authorized</i>	<i>Actual</i>	<i>Authorized</i>	<i>Actual</i>	<i>Authorized</i>	<i>Actual</i>	<i>Authorized</i>
Mean	52.97%	50.13%	52.89%	52.92%	51.75%	50.49%		49.30%
Median	52.80%	51.21%	53.23%	52.50%	52.54%	50.00%		52.15%

- b) In the scenario that the OEB is interested in considering two separate capital structures for nuclear and hydroelectric, please provide Concentric's recommended capital structure for each of the two generation types.
- c) Please provide Exhibit 4 in excel format.
- d) Please further explain the note at page 2 of Exhibit 4 as follows, "U.S. states that account for zero-cost of capital items in utilities' regulated capital structure (Florida, Arkansas, Indiana, and Michigan) were excluded from this analysis."
- e) Please further explain the note at page 2 of Exhibit 4 as follows, "Florida Power & Light's authorized equity ratio was included based on an analysis of the capital structure excluding zero cost of capital effects." Please provide a detailed explanation of any adjustments made to determine the current equity ratio for Florida Power and Light.

- 1 f) Please explain the “n/a” designations shown in Exhibit 4. If the current equity ratio  
2 for the operating subsidiaries where this ratio has been designated as “n/a” are  
3 available, please provide an alternative version of Exhibit 4 that includes these  
4 ratios in excel format.  
5
- 6 g) As an example, in EB-2024-0063 at Exhibit CEA-10.3, the Indiana Michigan Power  
7 Company (operating in Indiana) (a subsidiary of American Electric Power  
8 Company) is shown to have an authorized equity ratio of 40.7% and in the current  
9 proceeding the equity ratio is listed as “n/a.” Please explain why this subsidiary was  
10 included in the EB-2024-0063 equity thickness analysis and is excluded in the  
11 current proceeding.  
12
- 13 h) Please provide an alternative Exhibit 4 authorized equity ratio analysis using a 5-  
14 year average of the authorized ratios (instead of only the current authorized ratio)  
15 in the circumstance that the authorized ratio has changed over the most recent 5-  
16 year period.  
17
- 18 i) Please confirm that the average authorized equity ratio for the operating  
19 subsidiaries of Canadian companies is 46.35%.  
20
- 21 j) Please confirm that the average authorized equity ratio for the operating  
22 subsidiaries that operate within Canada is 40.60%.  
23
- 24 k) Please confirm that the holding company averages (Exhibit 4, p. 3 of the report)  
25 includes only the electric subsidiaries of the holding companies (i.e., page 3 is  
26 simply an average of the equity ratios for the electric subsidiaries of each holding  
27 company as shown on pages 1-2 of Exhibit 4).  
28  
29

30 **Response**  
31

32 *This response was prepared by Concentric Energy Advisors (“Concentric”):*  
33

- 34 a) Confirmed. Actual equity ratios for the “Most Credit Supportive” group are not  
35 available, since balance sheet data is not readily available at the jurisdiction-level.  
36 The “Most Credit Supportive” group was screened at the jurisdiction level since  
37 S&P affords rankings on a state-by-state basis.  
38
- 39 b) Concentric evaluates risk by generation type but determines a single deemed  
40 capital structure for OPG’s regulated generation because investors, rating  
41 agencies, and regulators assess financing and financial integrity on a consolidated  
42 regulated business basis. As such, Concentric does not have a recommended  
43 capital structure for each of the two generation types. Concentric agrees with the

1 OEB's view expressed in EB-2010-0008, wherein the OEB stated that separate  
2 equity ratios could introduce variability and complexity as technology-specific ratios  
3 change over time, there was no demonstrable evidence of significant ratepayer  
4 benefits, and determining technology-specific levels was heuristic and qualitative  
5 in nature.

6  
7 c) Please see Attachment 1 for the requested file.

8  
9 d) Several U.S. states (i.e., Arkansas, Florida, Indiana, and Michigan) account for  
10 zero-cost of capital items such as accumulated deferred income taxes or customer  
11 deposits in the regulated capital structure for utilities at zero cost, rather than as  
12 reductions to rate base. Those recent authorized equity ratios per the Regulatory  
13 Research Associates database (i.e., the main source of Concentric's data) are not  
14 comparable because they incorporate zero cost or non investor supplied capital  
15 components directly into the authorized equity ratio, which can distort comparability  
16 across utilities. In the case of NextEra Energy, Concentric relied on direct  
17 knowledge of utility specific regulatory and capital structure information gained  
18 through Concentric's participation in that rate case to ensure that the equity ratio  
19 used in the analysis reflects a conventional common equity component excluding  
20 zero-cost capital components that is comparable across the broader proxy group.

21  
22 e) Please see the response to part d) of this response, and also please see the  
23 response to Ex. L-C1-Staff-301, parts a) and b).

24  
25 f) A designation of "n/a" indicates that either 1) S&P Capital IQ (i.e., the source relied  
26 on by Concentric for authorized equity ratio data) specified "n/a" for the equity ratio  
27 for that operating subsidiary's most recent rate case, which commonly occurs when  
28 the regulatory decision in the case does not specify the capital structure, for  
29 instance if there was a "black-box" settlement or an otherwise not publicly-available  
30 authorized equity ratio, or 2) S&P Capital IQ reported the capital structure inclusive  
31 of zero-cost of capital items, which renders the capital structure directly  
32 incomparable to OPG's financial capital structure.

33  
34 In response to this interrogatory, Concentric has undertaken additional analysis on  
35 the cases originally marked "n/a" due to operations in a state that authorizes zero-  
36 cost of capital items in the utilities' capital structure. There were nine such cases in  
37 Concentric's original analysis. Attachment 2 (which is a modified version of the  
38 "Holding Company Averages" and "Authorized Equity Ratios" tabs of Concentric's  
39 workpaper labeled "Authorized Equity Ratio Analysis Workpaper – PUBLIC")  
40 adjusts those cases' authorized equity ratios to exclude zero-cost of capital items  
41 based on an analysis of orders, settlements, and testimony. Those nine cases  
42 averaged a 50.37% equity ratio excluding zero-cost sources of financing, with a  
43 median of 50.00%. Including these cases in the overall authorized equity ratio

1 analysis would not significantly alter the results; for example the overall average  
 2 and median results would not change by more than nine basis points.

3  
 4 g) Please see Attachment 3, which is a February 23, 2022 order from the Indiana  
 5 Utility Regulatory Commission in Indiana Michigan Power Company's ("Indiana  
 6 Michigan's") rate case in Cause No. 45576. Page 41 of that order provides the  
 7 capital structure for Indiana Michigan including a zero-cost capital item for  
 8 accumulated deferred income taxes (17.81 percent of the capital structure) and  
 9 other non-investor-supplied sources of capital (i.e., customer deposits and  
 10 investment tax credits). Including zero-cost and other non-investor-supplied  
 11 sources of capital results in an equity ratio for Indiana Michigan of 40.70 percent,  
 12 as shown on page 41 of the order and in the chart below.

13 **Chart 1 – Phase II Capital Structure and Weighted Cost of Capital**

14

<u>Description</u>	<u>Total Company Capitalization</u> (\$)	<u>Percent of Total</u>	<u>Cost Rate</u>	<u>Weighted Average Cost of Capital</u>
Long-Term Debt	2,873,862,352	40.70%	4.44%	1.81%
Common Equity	2,873,862,352	40.70%	9.70%	3.95%
Customer Deposits	41,698,455	0.59%	2.00%	0.01%
Acc. Def. FIT	1,257,846,893	17.81%	0.00%	0.00%
Acc. Def. JDITC	<u>13,678,705</u>	<u>0.19%</u>	7.07%	<u>0.01%</u>
Total	<u>7,060,948,756</u>	100.00%		<u>5.78%</u>

15  
 16  
 17 As also stated on that page of the order, "the Settlement Agreement provides the  
 18 debt/equity ratio for investor-supplied capital will be adjusted to the December 31,  
 19 2022, actual ratio but no higher than a 50.00% equity ratio." As such, the investor-  
 20 supplied capital structure, which is comparable to OPG's deemed capital structure,  
 21 includes 50.00 percent equity. In EB-2024-0063, Concentric failed to exclude or  
 22 adjust the 40.70 percent equity ratio reported by Regulatory Research Associates  
 23 ("RRA") for Indiana resulting in an understated investor-supplied equity ratio for  
 24 Indiana Michigan in that proceeding.

25  
 26 h) Please see Attachment 4 for the requested data. Attachment 4 includes notes on  
 27 certain updates to current equity ratios where relevant to reflect additional  
 28 proceedings and/or updates to RRA's rate case database since the time of  
 29 Concentric's original analysis in this proceeding. Finally, with respect to the proxy  
 30 group, the alternative Exhibit 4 reflects the inclusion of Virginia Electric and Power  
 31 Company's Virginia jurisdiction, consistent with Concentric's response to Ex. L-C1-  
 32 Staff-302 parts a) and b). As shown in Attachment 4, these updates resulted in a  
 33 slight increase to the mean and median results of the main proxy group and the  
 34 minimum and mean results for the nuclear subgroup.

- 1 i) Confirmed.
- 2
- 3 j) Confirmed.
- 4
- 5 k) Confirmed.

**ORIGINAL**

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner			√

**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

**PETITION OF INDIANA MICHIGAN POWER )  
COMPANY, AN INDIANA CORPORATION, )  
FOR AUTHORITY TO INCREASE ITS RATES )  
AND CHARGES FOR ELECTRIC UTILITY )  
SERVICE THROUGH A PHASE IN RATE )  
ADJUSTMENT; AND FOR APPROVAL OF )  
RELATED RELIEF INCLUDING: (1) REVISED )  
DEPRECIATION RATES; (2) ACCOUNTING )  
RELIEF; (3) INCLUSION OF CAPITAL )  
INVESTMENT; (4) RATE ADJUSTMENT )  
MECHANISM PROPOSALS; (5) CUSTOMER )  
PROGRAMS; (6) WAIVER OR DECLINATION )  
OF JURISDICTION WITH RESPECT TO )  
CERTAIN RULES; AND (7) NEW SCHEDULES )  
OF RATES, RULES, AND REGULATIONS. )**

**CAUSE NO. 45576**

**APPROVED: FEB 23 2022**

**ORDER OF THE COMMISSION**

**Presiding Officers:**

**David L. Ober, Commissioner**

**Carol Sparks Drake, Senior Administrative Law Judge**

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On July 1, 2021, Indiana Michigan Power Company (“I&M” or “Petitioner”) filed a Petition with the Indiana Utility Regulatory Commission (“Commission”) seeking authority to increase its rates and charges for electric utility service and associated relief.<sup>1</sup> On July 1, 2021, Petitioner also filed its case-in-chief, workpapers, and information required by the minimum standard filing requirements (“MSFRs”) set forth at 170 Ind. Admin. Code (“IAC”) 1-5-1 *et seq.* I&M’s case-in-chief included testimony, attachments, and workpapers from the following witnesses:

- Toby L. Thomas, I&M President and Chief Operating Officer <sup>2</sup>
- Brent E. Auer, I&M Regulatory Analysis and Case Manager in the Regulatory Services Department <sup>3</sup>
- David A. Lucas, I&M Vice President – Regulatory and Finance
- David S. Isaacson, I&M Vice President of Distribution Operations
- Quinton Shane Lies, I&M Site Vice President at Donald. C. Cook Nuclear Plant
- Timothy C. Kerns, American Electric Power Service Corporation’s (“AEPSC”) Vice President – Generating Assets for I&M and Kentucky Power Company
- Dona Seger-Lawson, I&M Director of Regulatory Services
- Nicolas C. Koehler, Director of East Transmission Planning for AEPSC
- Nancy A. Heimberger, AEPSC Financial Analyst Senior Staff in Corporate Planning and Budgeting <sup>4</sup>
- Andrew J. Williamson, I&M Director of Regulatory Services
- Curtis H. Bech, Senior Manager, Utilities Strategy and Consulting, Accenture PLC
- Jon C. Walter, I&M Consumer and Energy Efficiency Programs Manager
- Jason A. Cash, AEPSC Accounting Senior Manager in Corporate Accounting
- Aaron L. Hill, AEPSC Director of Trusts and Investments
- Roderick W. Knight, Decommissioning Manager, TLG Services, Inc.
- Jessica M. Criss, AEPSC Tax Accounting and Regulatory Support Manager
- Ann E. Bulkley, Senior Vice President, Concentric Energy Advisors, Inc. (“Concentric”)
- Franz D. Messner, AEPSC Managing Director of Corporate Finance
- Tyler H. Ross, AEPSC Director of Regulatory Accounting Services
- Chad M. Burnett, AEPSC Director of Economic Forecasting
- Jennifer C. Duncan, AEPSC Regulatory Consultant Staff in the Regulated Pricing and Analysis Department
- Stephen Hornyak, AEPSC Regulatory Consultant Principal in the Regulated Pricing and Analysis Department
- Jenifer L. Fischer, AEPSC Manager, Regulated Pricing and Analysis

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<sup>1</sup> On June 1, 2021, I&M provided its notice of intent to file a rate case in accordance with the Commission’s General Administrative Order 2013-5.

<sup>2</sup> On October 14, 2021, I&M filed a notice that Steven F. Baker, I&M’s current President and Chief Operating Officer, was being substituted for and adopting the prefiled testimony of Toby L. Thomas.

<sup>3</sup> On October 14, 2021, I&M filed a notice that Dona Seger-Lawson, I&M Director of Regulatory Services, was adopting Brent Auer’s prefiled testimony.

<sup>4</sup> On October 14, 2021, I&M filed a notice that Shelli A. Sloan, AEPSC Director Financial Support and Special Projects in Corporate Planning and Budgeting, was being substituted for and adopting the prefiled testimony of Nancy A. Heimberger.

- Kurt C. Cooper, I&M Regulatory Consultant Principal in the Regulatory Services Department.<sup>5</sup>

Petitions to Intervene were filed by the I&M Industrial Group,<sup>6</sup> (“IG” or “Industrial Group”);<sup>7</sup> The Kroger Company (“Kroger”); Steel Dynamics, Inc. (“SDI”); Walmart, Inc. (“Walmart”); Citizens Action Coalition of Indiana, Inc. (“CAC”); City of Fort Wayne, Indiana, (“Fort Wayne”); City of Marion, Indiana, and Marion Municipal Utilities (collectively, “Marion”); City of South Bend, Indiana (“South Bend” and collectively with Fort Wayne and Marion, the “Joint Municipals”); City of Auburn Electric Department (“Auburn”); Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance (“WVPA”); and City of Muncie, Indiana (“Muncie”). These petitions were granted without objection. The Indiana Office of Utility Consumer Counselor (“OUCC”) also participated.

On July 21, 2021, a Docket Entry was issued establishing a procedural schedule and related requirements and approving certain stipulations the parties filed on July 14, 2021.

Public field hearings were held on August 24, 2021, in South Bend, Indiana,<sup>8</sup> and on September 7, 2021, in Fort Wayne, Indiana, the largest municipality in Petitioner’s Indiana service area. On October 12, 2021, the OUCC and certain intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled written consumer comments and testimony and attachments from the following witnesses:

- Michael D. Eckert, Assistant Director of the OUCC’s Electric Division
- Mark E. Garrett, President of Garrett Group Consulting, Inc.
- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC
- Anthony A. Alvarez, Utility Analyst in the OUCC’s Electric Division
- Peter M. Boerger, PhD, Senior Utility Analyst in the OUCC’s Electric Division
- Cynthia M. Armstrong, Senior Utility Analyst in the OUCC’s Electric Division<sup>9</sup>
- John E. Haselden, Senior Utility Analyst in the OUCC’s Electric Division
- Kaleb G. Lantrip, Utility Analyst in the OUCC’s Electric Division
- Caleb R. Loveman, Utility Analyst in the OUCC’s Electric Division
- Wes R. Blakley, Senior Utility Analyst in the OUCC’s Electric Division
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

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<sup>5</sup> I&M filed additional MSFRs on July 13, 2021, and revisions to testimony on September 2, 2021, including a clarification of Mr. Cash’s direct testimony explaining how I&M plans to implement the calculated depreciation rates for the Rockport Plant as a whole.

<sup>6</sup> The I&M Industrial Group is a group of industrial customers located in I&M’s service territory and, ultimately, for purposes of this proceeding includes the following: General Motors LLC, I/N Tek L.P., Linde, Inc., Marathon Petroleum Company LP, Messer LLC, and the University of Notre Dame.

<sup>7</sup> General Motors LLC and the University of Notre Dame were added to the Industrial Group on September 30, 2021.

<sup>8</sup> No public comment was received at the South Bend field hearing.

<sup>9</sup> On November 4, 2021, the OUCC submitted a corrected version of Ms. Armstrong’s testimony and attachments to remove redactions for information subsequently determined to be public. At the evidentiary hearing, Ms. Armstrong’s corrected testimony and attachments were admitted.

The Industrial Group provided testimony and attachments from James R. Dauphinais and Michael P. Gorman, both Consultants and Managing Principals with Brubaker & Associates, Inc.<sup>10</sup>

Kroger prefiled the testimony and attachments of Justin Bieber, Senior Consultant for Energy Strategies, LLC.

Walmart prefiled the testimony and attachments of Steve W. Chriss, Director, Energy Services for Walmart.

CAC prefiled the testimony and attachments of John Howat, Senior Policy Analyst at the National Consumer Law Center.

Muncie prefiled the testimony and attachments of Muncie's Mayor and Chief Executive, Dan Ridenour, and Ryan Stout, National Solar Developer for Performance Services, Inc.

Joint Municipals provided testimony and exhibits from Joseph A. Mancinelli, Director and President Emeritus of NewGen Strategies and Solutions, LLC ("NewGen"), and Constance T. Cannady, Executive Consultant at NewGen.<sup>11</sup>

On November 9, 2021, the OUCC prefiled cross-answering testimony from Glen A. Watkins. That same day, the Industrial Group prefiled cross-answering testimony from James R. Dauphinais.

Also on November 9, 2021, I&M prefiled rebuttal testimony, exhibits, and workpapers for the following witnesses:

- David A. Lucas
- Andrew J. Williamson
- Dona Seger-Lawson
- David S. Isaacson
- Aaron L. Hill
- Jason A. Cash
- Ann E. Bulkley
- Franz D. Messner
- Tyler H. Ross
- Jessica M. Criss.
- Andrew R. Carlin, AEPSC Director of Compensation and Executive Benefits
- Kimberly Kaiser, AEPSC Director of Compensation
- Jon C. Walter
- Jennifer C. Duncan

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<sup>10</sup> On October 25, 2021, the Industrial Group submitted a corrected version of Mr. Gorman's testimony and attachments to remove redactions for information subsequently determined to be public. At the evidentiary hearing, Mr. Gorman's corrected testimony and attachments were admitted.

<sup>11</sup> On October 26, 2021, the Joint Municipals submitted a corrected version of Mr. Mancinelli's and Ms. Cannady's testimony and attachments to remove redactions for information subsequently determined to be public. At the evidentiary hearing, the corrected testimony and attachments were admitted.

- Stephen Hornyak
- Jenifer L. Fischer
- Kurt C. Cooper.

On November 16, 2021, I&M, the OUCC, the Industrial Group, CAC, Auburn, Joint Municipals, Muncie, Kroger, WVPA, and Walmart (collectively, the “Settling Parties”) filed an Unopposed Joint Motion for Leave to File Settlement Agreement and Request for Settlement Hearing (“Joint Motion”). In the Joint Motion, the Settling Parties advised a settlement had been reached resolving all issues in this proceeding.<sup>12</sup> Attached to the Joint Motion was a copy of the Settling Parties’ Stipulation and Settlement Agreement (“Settlement Agreement”) dated November 16, 2021, including attachments. That same date, I&M also submitted a Stipulation and Settlement between I&M and Muncie (“Muncie Settlement Agreement”) dated November 16, 2021.

By Docket Entry dated November 18, 2021, the procedural schedule was revised to accommodate presentation of the settlement and supporting evidence.

On November 19, 2021, I&M prefiled the settlement testimony, attachments, and workpapers of Andrew J. Williamson supporting both the Settlement Agreement and the Muncie Settlement Agreement. Also on November 19, 2021, the OUCC and the Industrial Group each filed settlement testimony from the following witnesses supporting the Settlement Agreement:

- Michael D. Eckert
- Michael P. Gorman
- James R. Dauphinais.

A request for information was issued by Docket Entry on December 9, 2021, to which Muncie, the OUCC, and I&M responded on December 13 and 14, 2021.

A public settlement hearing was conducted in this Cause commencing at 9:30 a.m. on December 17, 2021, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the Settlement Agreement, Muncie Settlement Agreement, and all of the direct, cross-answering, rebuttal, and settlement testimony and exhibits each party prefiled, as well as the responses to the December 9, 2021 Docket Entry, were offered and admitted without objection. Per the terms of the Settlement Agreement, the parties also waived cross-examination of each other’s witnesses.

The Commission, based upon applicable law and the evidence, finds as follows:

**1. Notice and Jurisdiction.** Legal and timely notice of the public evidentiary hearing originally scheduled to commence in this Cause on December 2, 2021, was given and published as required by law, with this hearing converted by Docket Entry to a settlement hearing to be held on December 17, 2021, consistent with 170 IAC 1-1.1-18(m). I&M is a public utility as defined in

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<sup>12</sup> The Joint Motion indicated one remaining party in this case, SDI, was included in the settlement communications but is not a party to the Settlement Agreement. Joint Motion, ¶ 3. The Joint Motion further indicated SDI has no objection to the Settlement Agreement and will be waiving cross-examination. Joint Motion, ¶ 3.

Ind. Code § 8-1-2-1(a). Under Ind. Code §§ 8-1-2-42 and 42.7, the Commission has jurisdiction over I&M's rates and charges for utility service. The Commission, therefore, has jurisdiction over Petitioner and the subject matter of this proceeding.

**2. Petitioner's Organization and Business.** I&M is a public utility with its principal place of business located at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M renders electric utility service to approximately 470,000 retail customers located in the following Indiana counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley. I&M also provides electric service in Michigan to approximately 130,000 retail customers. Additionally, I&M is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is a member of PJM Interconnection, L.L.C. ("PJM"), a regional transmission organization operated under the FERC's authority that controls the use of I&M's transmission system and the dispatching of I&M's generating units.

I&M renders electric service by means of electric production, transmission, and distribution plant, as well as general property, equipment, and related facilities, including office buildings, service buildings, and other property that are used in the production, transmission, delivery, and furnishing of electric energy, heat, light, and power. I&M classifies its property in accordance with the Uniform System of Accounts as prescribed by the FERC and approved and adopted by the Commission.

**3. Existing Rates.** The Commission approved I&M's current base rates and charges on March 11, 2020, in its Order in Cause No. 45235 ("45235 Order") based upon test year operating results for the 12 months ended December 31, 2020. The petition initiating Cause No. 45235 was filed with the Commission on May 14, 2019; consequently, in accordance with Ind. Code § 8-1-2-42(a), it has been more than 15 months since I&M filed its most recent petition for an increase in basic rates and charges and the filing of I&M's petition in this Cause.

**4. Test Year and Rate Base Cutoff.** As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period using projected data, with the test year used for determining Petitioner's projected operating revenues, expenses, and net operating income being the 12-month period ending December 31, 2022. I&M is utilizing the test year end, December 31, 2022, as the general rate base cutoff date. The historical base period is the 12-month period ending December 31, 2020.

**5. I&M's Requested Relief.** In its Petition, I&M requested Commission approval of an overall annual increase in revenues of approximately \$104 million, or approximately 6.5%. Petition, ¶ 24. I&M proposed to implement the requested revenue increase in two steps through the Phase-In Rate Adjustment ("PRA") process used in Petitioner's two most recent basic rate cases. Under I&M's proposal, in Phase I, revenue will increase by approximately \$73 million or 4.55%, with the second step reflecting an increase of \$31 million, or approximately 2%, as adjusted for actual test year investments. As detailed in I&M's case-in-chief, Petitioner also requested Commission approval of specific accounting and ratemaking relief, including new depreciation accrual rates, modifications to rate adjustment mechanisms, and I&M's proposed revenue allocation and rate design.

6. **Opposition, Rebuttal, and Cross-Answering.** The OUCC and intervenors raised numerous challenges to Petitioner’s filing, including challenging rate base, rate of return, operation and maintenance (“O&M”) expenses, depreciation rates, rider proposals, cost of service allocation, and rate design. The extent to which these parties also disagreed with each other is shown in their cross-answering testimony. The extent to which I&M disagreed or agreed with the OUCC and intervenors was addressed in I&M’s rebuttal evidence.

7. **Settlement Agreement.** Messrs. Williamson, Eckert, Gorman, and Dauphinais presented testimony supporting the Settlement Agreement. They reviewed its terms and stated the Settlement Agreement resolves all issues related to I&M’s revenue requirements and rate design. Mr. Williamson testified this agreement settles all the issues among all of the parties in this Cause except SDI, with SDI not joining the settlement but also not opposing the Settlement Agreement. OUCC witness Eckert stated that if approved, the Settlement Agreement will provide certainty regarding critical issues, including revenue requirements, Petitioner’s authorized return, and the allocation of I&M’s revenue requirement among its rate classes. Mr. Gorman stated that at a high level, the settlement brought the Settling Parties together to negotiate a wide range of contested matters, including I&M’s approved return on equity, proposed capital structure, the regulatory treatment of capacity costs previously excluded from retail rates, I&M’s position upon the Tax Sharing Agreement and treatment of Net Operating Loss Carryforward (“NOLC”), and the treatment of the costs associated with Rockport Unit 2.

All four witnesses providing settlement testimony testified the Settlement Agreement is a product of intense negotiations, with each party offering compromise to challenging issues. Public’s Ex. 15 at p. 2; Petitioner’s Ex. 15 at pp. 6-8; Intervenor IG Ex. 4 at pp. 3, 5; Intervenor IG Ex. 5 at pp. 2, 6. Per Mr. Eckert, the nature of compromise includes assessing the litigation risk that the tribunal, in this case the Commission, will find the other side’s case more compelling. While the Settlement Agreement balances all interests, given the number of benefits provided to ratepayers under the Settlement Agreement, Mr. Eckert testified the OUCC, as the statutory representative of all ratepayers, believes the Settlement Agreement is a fair resolution, is supported by the evidence, and should be approved. Public’s Ex. 15 at p. 2. Mr. Dauphinais added that while no party received the full measure of the positions they took in their respective case-in-chief, the total package balances the parties’ competing interests in favor of an overall result that is fair and reasonable. Intervenor IG Ex. 5 at p. 2. These witnesses opined that the Settlement Agreement represents the culmination of the parties’ efforts to come together through negotiations to find a result that reflects the purpose of utility regulation — the balancing of interests between the utility and its consumers. Public’s Ex. 15 at pp. 2, 8; Intervenor IG Ex. 4 at p. 3; Intervenor IG Ex. 5 at p. 2.

A. **Overview.** In describing how the Settlement Agreement is organized, Mr. Williamson testified Section I.A. addresses I&M’s test year revenue requirement and other matters while Section I.B. sets forth the Settling Parties’ agreement regarding revenue allocation, rate design, and certain tariff language changes. He stated Section I.C. addresses the remaining issues — namely, that any matters the Settlement Agreement terms do not address will be adopted as I&M proposed. Mr. Williamson added it is important to recognize the Settlement Agreement is

presented as a complete negotiated package that, taken as a whole, reflects compromise and the give and take of negotiations. Petitioner's Ex. 15 at p. 8.

Mr. Eckert stated the Settlement Agreement addresses the OUCC's concerns about the affordability of I&M's rate request by reducing I&M's requested revenue increase in several ways. Public's Ex. 15 at p. 2. For example, I&M's rate base request is reduced by \$26.4 million, consisting of reductions to: (1) forecasted distribution plant investment; (2) Electric Vehicle ("EV") Fast Charging capitalized costs; (3) Flex Pay Program capitalized costs; and (4) unamortized COVID-19 deferred bad debt expense. Public's Ex. 15 at pp. 2-3. He added that ongoing Rockport Unit 2 expenses and rate base related revenue requirements are removed under the Settlement Agreement from customer rates effective December 7, 2022, when the Rockport Unit 2 lease ends, and Unit 2 no longer provides retail energy utility service. Mr. Eckert testified that through December 7, 2022, I&M customers receive the benefit of the Commission's Cause No. 45235 excess capacity adjustment that I&M had proposed to stop applying when Phase I rates are implemented. He testified the Settlement Agreement also reduces O&M expenses by approximately \$6.3 million annually beyond the O&M reductions related to Rockport Unit 2. Public's Ex. 15 at p. 3.

Messrs. Eckert and Williamson also reviewed other customer benefits in the Settlement Agreement. Public's Ex. 15 at p. 5; Petitioner's Ex. 15 at pp. 29-34. These include: (1) continuation of the monthly residential customer charge of \$15.00 as opposed to I&M's originally proposed \$20.00 charge; (2) no change in I&M's current 9.70% authorized return on equity ("ROE"); (3) limiting I&M's debt to equity ratio in its weighted average cost of capital ("WACC") to no higher than 50.00% equity; (4) an annual PJM Network Integration Transmission Service ("NITS") cost cap for purposes of recovery through the PJM Rider; (5) retention of approximately \$159 million in cost free capital that I&M proposed to remove from its capital structure through its NOLC adjustment, pending receipt of a Private Letter Ruling ("PLR") from the Internal Revenue Service ("IRS"); (6) removal of I&M's proposed \$69.3 million (Indiana jurisdictional) Other Post-Retirement Employee Benefit ("OPEB") asset from Petitioner's rate base; (7) an agreed limitation on customer deposits to no more than \$50.00 for customers identified as Low Income Home Energy Assistance Program ("LIHEAP") participants or LIHEAP-eligible; and (8) additional negotiated benefits. Public's Ex. 15 at pp. 5-6; Petitioner's Ex. 15 at pp. 8-39.

**B. Revenue Requirement.** If the Settlement Agreement is approved, I&M's base rates will be designed to reflect a lower revenue requirement than I&M proposed in its case-in-chief. The Settling Parties agreed to a Phase I annualized combined basic rate and rider revenue requirement decrease of \$4.7 million, which is an approximate \$78 million reduction from I&M's requested Phase I increase of \$73 million. Public's Ex. 15 at p. 4. Mr. Eckert testified that as shown in Settling Parties' Joint Ex. 1, Settlement Agreement Attachment 1, this reduces the system-wide Phase I revenue increase impact from I&M's original proposal of 4.55% to a Phase I decrease of 0.29%. Public's Ex. 15 at p. 4.

Mr. Eckert stated the Settling Parties agreed to a Phase II annualized combined basic rate and rider revenue requirement decrease of \$95 million, representing an approximately \$199 million reduction from I&M's requested \$104 million increase. As shown in the Settling Parties' Joint Ex. 1, Settlement Agreement Attachment 1, this reduces the system-wide cumulative Phase II

revenue increase impact from I&M's original proposal of 6.5% to a decrease of 5.90%. Public's Ex. 15 at p. 4. Under the Settlement Agreement, the rate impact for all major classes is reduced as compared to what I&M originally proposed. Public's Ex. 15 at p. 4.

**C. Return on Equity, Capital Structure, and Rate of Return.**<sup>13</sup>

1. ROE and Capital Structure. In its case-in-chief, I&M proposed a 10.00% ROE. Several intervenors, including the OUCC and the Industrial Group, advocated for a considerably lower ROE. The testimony supporting the Settlement Agreement explained that as a result of the negotiations, a compromise was reached upon a 9.70% ROE. This is the same ROE the Commission found to be fair and reasonable under the totality of the circumstances in I&M's last basic rate case. The ROE component of the WACC used in each of I&M's capital riders will be 9.70%. Public's Ex. 15 at p. 6.

Mr. Eckert testified that a ROE lower than what I&M originally sought benefits ratepayers by reducing the return on rate base reflected in rates. He added that from the OUCC's perspective, using a 9.70% ROE for determining I&M's revenue requirement in its base rates and in I&M's ongoing capital riders more accurately reflects I&M's risk profile than Petitioner's proposed 10.00% ROE. Mr. Eckert stated that in addition, the lower ROE reduces the return on capital investment consumers must pay through capital riders between rate cases. Thus, OUCC witness Eckert testified the Settlement Agreement establishes a balanced plan that is in the interest of ratepayers while preserving I&M's financial integrity. Public's Ex. 15 at p. 6.

The Settlement Agreement also addresses Petitioner's capital structure at Section I.A.1.f. The Settling Parties agreed that for purposes of calculating the PRA for Phase I rates, the debt/equity ratio for investor supplied capital will be 50.54%/49.46%. Petitioner's Ex. 15 at pp. 14-15. As discussed by Messrs. Eckert, Gorman, and Williamson, for purposes of the Phase II compliance filing, I&M's debt/equity ratio associated with investor-supplied capital will be adjusted to its December 31, 2022, actual ratio but will not exceed 50.00% equity. Public's Ex. 15 at p. 7; Intervenor IG Ex. 4 at p. 3; Petitioner's Ex. 15 at p. 15. Petitioner's Ex. 15, Attachment AJW-1-S (which updates Exhibit A-7) sets forth the settlement WACC and Cost of Investor Supplied Capital for both Phases I and II.

2. NOLC. Messrs. Eckert, Gorman, and Williamson testified the Settlement Agreement resolves the contested issue regarding I&M's NOLC. Per Mr. Eckert, I&M will retain in its capital structure the approximately \$159 million in cost free capital that it proposed to remove through its proposed NOLC adjustment. Public's Ex. 15 at p. 8. Pending receipt of a PLR from the IRS, the Settling Parties agree the Commission should authorize I&M to establish a regulatory asset for the return associated with (1) the inclusion of the proposed NOLC adjustment in the calculation of accumulated deferred federal income taxes ("ADFIT") in I&M's capital structure and (2) for any differences in I&M's requested levels of protected and unprotected excess accumulated deferred income tax ("EADFIT") amortization and the settled levels of amortization. Public's Ex. 15 at p. 8; Petitioner's Ex. 15 at p. 10; Intervenor IG Ex. 4 at p. 4.

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<sup>13</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.1.

If the IRS issues a PLR in I&M's favor, i.e., concludes that failure to adopt I&M's position with respect to the NOLC adjustments would constitute a normalization violation, I&M will initiate a limited proceeding to update its Tax Rider to reflect the NOLC adjustments, along with any Commission-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. The Settling Parties reserved the right to take any position in this limited proceeding related to the NOLC and I&M's proposed related ratemaking. Under the Settlement Agreement, if the IRS PLR does not support I&M's proposed adjustment, I&M will write off the regulatory asset, and it will not be recovered from customers. The Settlement Agreement also sets forth a process by which the Settling Parties may participate in the PLR process and details I&M's obligation to confer with the Settling Parties on a neutral description of the facts and the language of the draft PLR request to objectively frame the issue while adhering to IRS guidelines and requirements before the PLR is submitted to the IRS for consideration. Public's Ex. 15 at pp. 8-9; Petitioner's Ex. 15 at p. 11.

Mr. Gorman testified this is a fair resolution as it provides customers the immediate benefit of a higher amount of cost-free capital in I&M's capital structure and provides consumers and I&M a means to obtain a final resolution from the IRS on the issue. Intervenor IG Ex. 4 at p. 4. He added that if the IRS finds a normalization violation would occur, the Settlement Agreement also acknowledges the Settling Parties' right to challenge the continued benefit of I&M remaining in the AEP Tax Sharing Agreement on a going forward basis.

3. Tax Rider. In her direct testimony, Ms. Seger-Lawson proposed implementing a Tax Rider to address the ongoing rate impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA") consistent with the mechanism approved in the 45235 Order (p. 74), and she explained how I&M will use deferral accounting to implement this Rider. Ms. Seger-Lawson also proposed approving use of the Tax Rider for future changes in the federal corporate income tax rate. This proposed expansion of the Tax Rider was challenged.<sup>14</sup>

Messrs. Eckert and Williamson addressed the Settlement Agreement provisions regarding the Tax Rider. Public's Ex. 15 at p. 10; Petitioner's Ex. 15 at pp. 13-14. Mr. Eckert stated I&M originally proposed to expand its Tax Rider to encompass future federal corporate income tax changes, but the Settling Parties agreed to not make this change. Public's Ex. 15 at p. 10. Instead, I&M's Tax Rider will serve two purposes: (1) to credit customers with EADFIT as outlined in the Settlement Agreement, and (2) in the event the IRS issues a PLR in I&M's favor upon its proposed NOLC adjustment, to implement any associated ratemaking changes. Public's Ex. 15 at p. 10; Petitioner's Ex. 15 at pp. 13-14.

More specifically, Mr. Williamson explained that simultaneous with the implementation of new base rates, I&M will implement a Tax Rider to credit customer rates for the remaining benefits associated with unprotected EADFIT. Petitioner's Ex. 15 at p. 14. He stated the Settling Parties agreed to also increase the amount of monthly amortization. This agreement will advance the benefit of this amortization to customers and, as a result, the amortization credit in the Tax Rider is expected to expire before the end of the test year. He added that for purposes of setting rates in this proceeding for the Tax Rider, I&M agreed not to adjust the remaining balance of unprotected EADFIT for any NOLC impact. I&M also agreed to a \$14,623,272 (Indiana jurisdictional) unprotected EADFIT credit as Joint Municipals witness Cannady proposed and a

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<sup>14</sup> OUCC Ex. 11 at pp. 14-15; Jt. Municipals Ex. 2 at p. 19; *see also* Petitioner's Ex. 31 at pp. 19-22.

seven-month amortization period. Petitioner's Ex. 15 at p. 14. Mr. Williamson explained that the total monthly unprotected EADFIT amount to be credited to customers through the Tax Rider will include a carrying charge on the unamortized balance based on the agreed pre-tax WACC. In addition, the monthly amortization will be grossed up for taxes at a rate of 1.3580 and will include carrying charges on the unamortized balance based on I&M's agreed pre-tax WACC. Petitioner's Ex. 15 at p. 14. Mr. Williamson testified the Settling Parties agreed I&M will reconcile the Tax Rider to reflect its actual unprotected EADFIT amortization and monthly remaining balance.

4. Net Operating Income. As stated by Mr. Williamson, under the Settlement Agreement, I&M's authorized base rate net operating income is \$296,733,906. Petitioner's Ex. 15 at pp. 15-16.

**D. Rockport Unit 2**.<sup>15</sup> Messrs. Eckert, Williamson, and Gorman testified the lower revenue requirement the Settling Parties agreed to reflects, in part, the terms of the separate, then-pending Rockport Settlement Agreement in Cause No. 45546 regarding Rockport Unit 2.<sup>16</sup> Mr. Gorman stated that consistent with the Rockport Settlement Agreement in Cause No. 45546, the Settling Parties reached agreement on how to remove approximately \$141 million in Rockport Unit 2 related costs from ongoing retail rates, while still recovering the costs I&M will continue to incur for most of the test year, until the Unit 2 lease expires on December 7, 2022. Intervenor IG Ex. 4 at p. 4. Messrs. Williamson and Gorman testified that the Settling Parties agreed to an efficient process to implement this, explaining that, essentially, the Settling Parties agreed almost all costs related to Rockport Unit 2 will be removed from base rates immediately upon implementation of I&M's new base rates associated with approval of the Settlement Agreement and, instead, recovered either through the riders by which they are already recovered or through a special charge included in the PRA Rider. Intervenor IG Ex. 4 at pp. 4-5; Petitioner's Ex. 15 at p. 17. Mr. Gorman stated that in the case of costs recovered through the PRA, the collection only lasts through the time Unit 2 continues to be used and useful in the provision of service to Indiana retail customers or until the test year costs are fully recovered, whichever occurs first. Intervenor IG Ex. 4 at p. 5.

Mr. Williamson testified that per Section I.A.2. of the Settlement Agreement, the PRA Rockport Unit 2 Charge will include the following:

- i. A return on a fixed \$15,143,223 (Indiana jurisdictional) level of fuel and consumables inventory through December 7, 2022, at I&M's Phase I WACC grossed up for taxes.
- ii. I&M will recover the prorated share of a fixed \$1,035,878 (Indiana jurisdictional) annual level of fuel handling and disposal expenses through December 7, 2022.
- iii. I&M will recover its Rockport Unit 2 lease expense incurred through the end of calendar year 2022, based on the prorated share of I&M's annual \$48,924,630 (Indiana jurisdictional) lease expense. Since the PRA Rockport

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<sup>15</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Sections I.A.2. and 3.

<sup>16</sup> The Commission approved the Rockport Settlement Agreement in Cause No. 45546 on December 8, 2021.

Unit 2 Charge will end on December 8, 2022, I&M's Rockport Unit 2 lease expense will be grossed up to recognize the full lease expense in 2022 for purposes of setting the PRA Rockport Unit 2 Charge.

- iv. I&M will recover the prorated share of a fixed \$13,240,324 (Indiana jurisdictional) annual level of other O&M expense (\$12,177,941) and property tax expense (\$1,062,383) through December 7, 2022.
- v. Revenue requirement for implementing the PRA Rockport Unit 2 Charge will be allocated and retail rates designed based on the Settling Parties' agreement.

Petitioner's Ex. 15 at p. 18. He stated this approach allows the removal of the Rockport Unit 2 costs from I&M's revenue requirement in a reasonable and efficient manner. Among other things, the use of the PRA Rockport Unit 2 Charge avoids the need for I&M to prepare, and all the parties and the Commission to review and process, two complete sets of tariffs and associated compliance support. Petitioner's Ex. 15 at pp. 18-19. He testified it is an efficient and transparent approach for timely removing these costs from base rates while maintaining recovery of these costs during the lease term. Mr. Williamson testified that upon the earlier of I&M determining it has fully recovered the PRA Rockport Unit Charge or December 7, 2022, I&M will submit a compliance tariff to the Commission under Cause No. 45576 to eliminate the PRA Rockport Unit 2 Charge from the PRA factors. He added that since this change will be fully eliminating this component, and the impact to the PRA is limited to the math associated with removing this component of the PRA factors, I&M asks the Commission to expeditiously approve the revision.

Messrs. Gorman and Williamson testified that with respect to other costs that are already primarily recovered through the Environmental Cost Rider ("ECR") and Resource Adequacy Rider ("RAR"), they will continue to be recovered through those riders until the Commission approves filings seeking revisions to those rider rates. Intervenor IG Ex. 4 at p. 5; Petitioner's Ex. 15 at pp. 19-20. Mr. Gorman added that those filings are to be timed by I&M to receive orders from the Commission at the end of 2022/beginning of 2023. Intervenor IG Ex. 4 at p. 5. Mr. Gorman stated that after that, the charges will be removed from those riders.

Mr. Williamson stated the Settling Parties agreed I&M will recover its actual Rockport Unit 2 Fuel Cost Adjustment ("FAC") eligible fuel expenses, consistent with current FAC cases, incurred through December 7, 2022. Petitioner's Ex. 15 at p. 20. I&M's base cost of fuel will include \$28,185,922 (total company), \$19,608,596 (Indiana jurisdictional), in embedded Rockport Unit 2 fuel costs that will serve as a proxy for replacement purchased power when Rockport Unit 2 is no longer used for retail energy needs. This amount is incorporated into I&M's fuel basing points of 13.110 mills per kWh, which will be reconciled to actual fuel costs in I&M's FAC proceedings. Mr. Williamson stated that continuing to include Rockport Unit 2 fuel expense in I&M's FAC basing point recognizes that at times I&M will have to purchase power from PJM and allows for a basing point that reasonably recognizes the amount of energy I&M may need to serve customers. Petitioner's Ex. 15 at p. 21.

Under Section I.A.3. of the Settlement Agreement, the remaining net book value of I&M's investment in the Rockport Unit 2 Generating Station will be removed from rate base and

recovered on a levelized basis. Mr. Williamson stated that when I&M makes its PRA compliance filing to implement final base rates (i.e., Phase II), I&M will adjust the PRA to reflect the removal of the remaining net book value of Rockport Unit 2 of \$77,687,384 (Indiana jurisdictional) from rate base. At that time and going forward through December 31, 2028, I&M will be permitted to recover a total of \$95,639,514 (Indiana jurisdictional) associated with the net book value of Rockport Unit 2, on a levelized basis, in I&M's ECR (or alternative rate adjustment mechanism if the ECR is discontinued in the future). Petitioner's Ex. 15 at p. 21. Mr. Williamson testified the final PRA compliance filing made in January 2023 will result in final PRA tariff rates that will be applicable until I&M implements new base rates in its next general rate case. Mr. Gorman testified this is a reasonable means to effectuate the removal of Rockport Unit 2 related costs from retail rates, consistent with the Rockport Settlement Agreement in Cause No. 45546.

Mr. Eckert testified the Settlement Agreement also incorporates other expense reductions consistent with the terms of the Rockport Settlement Agreement. Public's Ex. 15 at p. 5. Mr. Eckert added that it is the OUCC's intention and belief that the Settlement Agreement reasonably implements and does not modify the terms of the Rockport Settlement Agreement. He added that the expiration of the Rockport Unit 2 lease will result in significant reductions in I&M's costs and, therefore, its cost of providing retail energy service to Indiana customers.

**E. Jurisdictional Reallocation.**<sup>17</sup> As discussed by Mr. Williamson, the prefiled cases-in-chief reflect a dispute regarding the treatment of the excluded capacity from Cause No. 45235. The OUCC, IG, and Joint Municipals took the position that the adjustment the Commission ordered in Cause No. 45235, or some version of that adjustment, should continue at least until the Rockport Unit 2 lease ends on December 7, 2022, at which point I&M will no longer have the excess capacity that supported the Commission's prior decision. Petitioner's Ex. 15 at p. 22. Mr. Williamson's rebuttal testimony explained I&M's need to meet its PJM capacity obligation as of June 1, 2022, at which point the Rockport Unit 2 capacity will be unavailable to I&M to meet its PJM obligation absent acquisition of the unit or a separate agreement making the capacity available through the entirety of the planning year.

Messrs. Gorman and Williamson testified that in their negotiations, the Settling Parties resolved the treatment of capacity related costs the Commission previously excluded from allocation to Indiana's retail customers in Cause No. 45235. Specifically, I&M has agreed to implement a monthly credit from the date rates first take effect through December 7, 2022, when the Rockport Unit 2 lease expires, to effectively remove those capacity-related costs from retail rates. Intervenor IG Ex. 4 at p. 4. Mr. Williamson stated I&M agreed to implement Phase I rates and to simultaneously implement a temporary PRA Excluded Capacity Credit to credit customers for excluded capacity costs consistent with the 45235 Order, with the credit to be eliminated from the PRA on a service-rendered basis effective December 8, 2022. He stated the credit will be developed based on a monthly amount of \$4,702,533 offset by the fixed annual level of retained capacity and Off System Sales revenues of \$24,926,096, prorated to a monthly level of \$2,077,175, for a net monthly credit of \$2,625,358. Petitioner's Ex. 15 at p. 23. Mr. Williamson testified that I&M will submit a compliance tariff to the Commission under this Cause to eliminate the PRA Excluded Capacity Credit from the PRA factors. He added that since this change will be fully eliminating this component, and the impact to the PRA is limited to the math associated with

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<sup>17</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.4.

removing this component of the PRA factors, I&M asks the Commission to expeditiously approve the revision.

Mr. Gorman opined that this fairly reflects adherence to the 45235 Order during most of the test year and the change that will occur in I&M's capacity position after December 7, 2022, when the Rockport Unit 2 lease expires.

**F. PJM NITS Costs.**<sup>18</sup> As stated by Messrs. Eckert, Dauphinais, and Williamson, the Settling Parties have agreed to place an annual cap on I&M's PJM NITS costs reflected in specific FERC accounts (4561035 and 5650016) that may be recovered through the PJM Rider based on I&M's 2024 forecasted Indiana jurisdictional amount of these costs, plus a 15% buffer. Public's Ex. 15 at pp. 3-4, 9; Intervenor IG Ex. 5 at p. 3; Petitioner's Ex. 15 at p. 24. The witnesses stated annual PJM NITS costs in any year that exceed \$381.3 million, together with the associated PJM NITS rider revenue requirement and carrying costs, will be placed in a regulatory asset for recovery in I&M's next base rate case. They clarified that the Settling Parties reserve the right to take any position with respect to the appropriate amortization period and related going forward return on any unamortized balance of any regulatory asset created under this term of the Settlement Agreement. Mr. Eckert testified PJM NITS are a significant expense borne by I&M's customers, and the agreed annual cost cap is an important guardrail to contain this cost in a given period. Public's Ex. 15 at pp. 3-4. He added that the compromise the Settling Parties made with regard to PJM NITS costs provides limitations on I&M's PJM NITS cost recovery. The annual cost cap provides flexibility, allowing I&M to recover costs over or under its annual forecasted amounts, plus an additional 15%. In addition, Mr. Eckert stated the cap limits the PJM NITS cash recovery from ratepayers through the designated period.

**G. Base Cost of Fuel.** Mr. Eckert stated that for purposes of settling Phase I rates, the Settling Parties accepted I&M's base cost of fuel of 13.110 mills per kWh. Public's Ex. 15 at p. 11.

**H. Advanced Metering Infrastructure ("AMI").**<sup>19</sup> The testimony supporting the Settlement Agreement also included the Settling Parties' negotiated resolution with respect to AMI. Messrs. Eckert and Williamson testified the Settling Parties: (1) agreed to include I&M's \$54.649 million AMI capital 2021-2022 forecast and \$4.77 million in related O&M costs in the base rates set in this Cause; and (2) I&M agreed to withdraw its request for an AMI rider. Mr. Williamson stated the Settlement Agreement makes clear that I&M is not prevented from seeking recovery of additional AMI investment and O&M costs in its next base rate case. Petitioner's Ex. 15 at p. 25. He added that the noncompany Settling Parties agreed to not challenge the reasonableness of I&M's decision to transition from AMR meters to AMI meters or the reasonableness of I&M's four-year deployment plan, as presented in this Cause, in any future proceeding. Petitioner's Ex. 15 at p. 25.

As further discussed below, I&M also agreed to notify its customers via bill insert, text, and email about its ability to remotely disconnect/reconnect those with AMI meters. Public's Ex. 15 at p. 12; Petitioner's Ex. 15 at p. 30. Per Mr. Williamson, this notice will identify a customer's

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<sup>18</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.5.

<sup>19</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.6.

rights prior to disconnection and provide information on how to contact I&M’s customer service department and on how to add an email address and/or mobile phone number to receive notifications from I&M.

**I. Rate Base.**

1. Prepaid Pension and OPEB Assets.<sup>20</sup> For purposes of reaching an overall settlement, Messrs. Eckert and Williamson stated the Settling Parties agreed I&M’s rate base will include the \$80.7 million (total company), \$58.1 million (Indiana jurisdictional) prepaid pension asset. Public’s Ex. 15 at p. 12; Petitioner’s Ex. 15 at pp. 25-26. Mr. Eckert noted the Commission has approved inclusion of a prepaid pension asset in I&M’s rate base in I&M’s three prior rate cases, Cause Nos. 44075, 44967, and 45235. Public’s Ex. 15 at p. 12. Under the Settlement Agreement, I&M’s proposed \$96,252,892 (total company), \$69,324,472 (Indiana jurisdictional), OPEB prepayment will not be included in Petitioner’s rate base. Public’s Ex. 15 at p. 13; Petitioner’s Ex. 15 at p. 26.

2. Agreed Rate Base Reductions.<sup>21</sup> Mr. Williamson testified that for purposes of calculating the revenue requirement used to set base rates, I&M agreed to reduce its proposed rate base by \$26.4 million, removing the following: (1) \$3,783,088 EV Fast Charging costs; (2) \$568,770 Flex Pay Program costs; (3) \$2,023,141 unamortized COVID-19 deferred bad debt expense; and (4) \$20 million of forecasted distribution plant investment. Petitioner’s Ex. 15 at p. 26. He stated the Settlement Agreement clarifies that nothing in that agreement precludes I&M from seeking to include the removed items in its cost of service in a future case. Mr. Williamson stated that in I&M’s view, this clarification recognizes the need for ongoing distribution system investment while at the same time allowing I&M to reduce the impact new base rates will have on its customers. Mr. Williamson testified the Settlement Agreement also allows I&M the opportunity to revisit the EV Fast Charging and the Flex Pay Program proposals and potentially pursue them in future proceedings. He presented the following summary of I&M’s settlement rate base:

Net Plant In-Service	\$	4,846,054,499
Fuel Stock	\$	29,521,506
Other Materials & Supplies	\$	124,206,512
Allowance Inventory	\$	17,674,176
Prepaid Pension Expense	\$	58,104,811
Regulatory Assets	\$	49,998,924
	\$	5,125,560,428

**J. Depreciation Rates.**<sup>22</sup> I&M also seeks approval of revised depreciation rates as presented by Mr. Cash. In describing how his depreciation study compared to the study presented in Cause No. 45235, Mr. Cash explained that in this depreciation study, all of I&M’s investment in Rockport Unit 1 and certain leasehold improvements made at Rockport Unit 2 are presented together as the Rockport Plant, and depreciation rates were calculated for each utility

<sup>20</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.A.7.

<sup>21</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.A.8.

<sup>22</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.A.9.a.

account used by the Rockport Plant. Petitioner's Ex. 19 at pp. 14-15. He stated the depreciation rates approved in Cause No. 45235 established depreciation rates for the investment in Rockport Unit 2 through 2028 for the Unit 2 SCR, through 2025 for the Unit 2 DSI, and through 2022 for the other investment at Unit 2. The proposed depreciation rates in this case depreciate the remaining net book value of all Rockport Plant investment through December 31, 2022, through 2028. Mr. Cash testified this allows for all of the remaining Rockport Plant investment in this case to be recovered over the plant's remaining life or through 2028. He stated I&M has not proposed depreciation rates specific to the Rockport Unit 2 leasehold improvements I&M owns and explained how depreciation expense will be calculated for the Rockport Unit 2 leasehold improvements while Rockport Unit 2 remains in service. Petitioner's Ex. 19 at pp. 20-21. More specifically, Mr. Cash stated the proposed depreciation rates were calculated to recover the remaining investment and net salvage of both Unit 1 and Unit 2 using the gross plant balance and remaining life of Unit 1; therefore, the depreciation rates the Commission approves will only be applied to the Unit 1 gross plant investment to determine I&M's depreciation expense for the Rockport Plant as a whole, including Unit 2.

Mr. Cash stated once the Commission approves new depreciation rates in this case and while Unit 2 remains in-service, I&M will apply a depreciation rate of 0% to Rockport Unit 2 for accounting purposes. For accumulated depreciation purposes, while Rockport Unit 2 remains in service, a portion of the depreciation expense on the Rockport Plant will continue to be applied to Rockport Unit 2. Mr. Cash testified that by applying the proposed rates only to Unit 1, I&M will calculate annual depreciation expense associated with the remaining investment and net salvage associated with both Unit 1 and Unit 2. If I&M were to apply a depreciation rate to Unit 2 other than 0%, he testified it would overstate I&M's annual depreciation accrual, exceed the annual depreciation expense included in I&M's proposed rates in this proceeding, and negatively impact I&M's net operating income. Mr. Cash explained this approach was taken to reflect the expiration of the Rockport Unit 2 lease in December 2022, which is also the end of I&M's forecasted test year in this case.

Mr. Williamson testified that under the Settlement Agreement, depreciation expense will be reduced by \$10 million. Petitioner's Ex. 15 at p. 27. To implement this, I&M reduced depreciation expense through a combination of expense reductions related to the rate base reductions associated with utility plant investments and revised distribution plant depreciation rates. Mr. Williamson stated the OUCC's pre-filed testimony includes several proposals to adjust I&M's distribution plant depreciation rates, and the revised distribution plant depreciation rates include acceptance of the OUCC's depreciation rate proposals for certain distribution FERC plant accounts<sup>23</sup> (but not the methodology) and a compromise the OUCC and I&M made with respect to certain distribution FERC plant accounts. Mr. Williamson presented the revised depreciation rates in Attachment AJW-2-S. He noted that under the Settlement Agreement any matters not addressed in the Settlement Agreement will be adopted as proposed by I&M.

**K. Other Agreed Operating Expense Reductions.**<sup>24</sup> Messrs. Williamson and Eckert testified the Settling Parties agreed to the following additional operating expense reductions: \$2.0 million in nuclear decommissioning expense; \$293,773 deferred COVID-19 bad

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<sup>23</sup> FERC plant accounts 365, 366, and 367.

<sup>24</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) Section I.A.9.b.-d.

debt expense; and \$4.0 million decrease in other O&M expense from I&M's test year forecast. Petitioner's Ex. 15 at pp. 27-28; Public's Ex. 15 at p. 13. Mr. Williamson added that the Settling Parties agree I&M may in the future seek to adjust the funding level of the Nuclear Decommissioning Trust based on future analysis of the adequacy of the Nuclear Decommissioning Trust funds to pay for decommissioning. He added that in the Settlement Agreement, the Settling Parties accept OUCC witness Blakley's proposal to reduce the incremental bad debt expense amortization by \$293,773, and Mr. Williamson stated that while I&M disagrees with the basis for the OUCC's proposed adjustment, in the context of the overall settlement, Petitioner accepted this proposal as part of the goal of mitigating the impact of this case on customer rates. Mr. Williamson stated the Settlement Agreement recognizes that other aspects of I&M's test year O&M forecast were challenged, and he explained that while I&M stands behind its forecasting process, in the spirit of compromise I&M agreed to reduce forecasted O&M by \$4.0 million. Mr. Williamson also clarified that the Settlement Agreement does not preclude I&M from seeking recovery of these type of expenses in a future case.

**L. Other Matters.**<sup>25</sup> Mr. Williamson testified the Settlement Agreement also addresses issues the OUCC and intervenors raised regarding the OUCC's Report in I&M's FAC, Vegetation Management Reporting, Notice of Disconnection of Service, Solar Power Rider, Flex Pay Program, EV Fast Charging, Low Income Customers, and Indiana Ratepayer Trust. Petitioner's Ex. 15 at pp. 29-34. These provisions are discussed below.

**M. Cost of Service and Rate Design.**<sup>26</sup> The revenue allocation/rate design provisions of the Settlement Agreement were also addressed in the settlement testimony.

1. **Revenue Allocation.**<sup>27</sup> Per OUCC witness Eckert, the Settling Parties negotiated a fair and reasonable revenue class allocation to allocate the costs of service among all rate classes. Public's Ex. 15 at p. 13; *see also* Intervenor IG Ex. 5 at pp. 3-4; Petitioner's Ex. 15 at pp. 34-35. As stated in the Settlement Agreement at Section I.B.1., the agreed allocation is without reference to any specific cost allocation methodology and was determined strictly for settlement purposes. Mr. Dauphinais testified the settlement includes an agreed revenue allocation that is without reference to any specific allocation methodology. Intervenor IG Ex. 5 at p. 2. Given the differing opinions among the Settling Parties on the proper method of cost allocation, he believes this is an important term that reflects the Settling Parties' overall efforts to put aside their differences to arrive at a result that is within the range of outcomes the evidence supports and results in a fair allocation of the overall revenue requirement among I&M's rate classes. Intervenor IG Ex. 5 at p. 2.

Petitioner's Exhibit 15, Attachment AJW-3-S (public), which updates Attachments JLF-2 and JLF-3 to reflect the Settlement Agreement, provides supporting details including the customer class revenue allocation factors and detailed base rate, rider, and total bill increase by class. The confidential version of this attachment is identified as Attachment AJW-3-S-(C) (confidential). Petitioner's Ex. 15 at p. 35.

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<sup>25</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) Section I.A.10.

<sup>26</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) Section I.B.

<sup>27</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.2.

Mr. Dauphinais also testified the Settling Parties agreed that with respect to the new charge in the PRA Rider associated with the collection of costs related to Rockport Unit 2, the revenue requirement will continue to be allocated on the same energy and demand basis as is used to allocate other rider revenue requirements. This means, effectively, that demand-related costs will still be allocated on a demand basis, and energy-related costs will still be allocated on an energy basis in conformance with basic cost of service principles.

Mr. Eckert added that since the OUCS represents all customer classes, the OUCS views the task of revenue allocation as one of ensuring any cost increases are fairly distributed across rate classes. Public's Ex. 15 at p. 14. He stated that because the Settlement Agreement results in overall rate decreases, the OUCS focused on ensuring the benefits of that overall reduction were fairly distributed.

2. Residential Rate Design.<sup>28</sup> Mr. Eckert confirmed the Settlement Agreement does not increase I&M's current Tariff RS monthly charge. Public's Ex. 15 at p. 14. He testified the OUCS's longstanding position is that a residential customer charge should not reflect more than the direct cost of connecting a customer to the distribution system from the standpoint of economic efficiency and regulatory policy. Mr. Eckert advised that in its case-in-chief, I&M proposed a 33% or \$5.00 increase in the residential fixed charge from \$15.00 to \$20.00. Mr. Williamson testified that while I&M has firmly held positions regarding the application of cost of service and cost recovery principles to residential rate design, Petitioner recognizes the passion around this issue, particularly in the testimony residential consumer advocates offered, with these diverging views making this issue challenging to resolve. Petitioner's Ex. 15 at p. 35. Mr. Eckert stated the monthly customer charge was the subject of deliberate negotiations, and through compromise, the Settling Parties agreed to maintain the monthly customer charge of \$15.00 for Rate RS and to increase the fixed Rate RS-TOD and Rate RS-TOD2 monthly charge to \$17.00. Mr. Eckert also testified the Settling Parties agreed to limit the customer deposit to no more than \$50.00 for customers identified as LIHEAP participants or LIHEAP-eligible.

3. Tariff IP.<sup>29</sup> With respect to Tariff IP, Mr. Dauphinais stated that in his direct testimony, he was concerned I&M was proposing to shift demand-related costs into the first block energy charge as a result of a shift from kVA billing demand to kW billing demand units. He proposed all demand-related costs be removed from the energy charges and placed back into the demand charges. Mr. Dauphinais testified this is essentially what was done in arriving at the rates in the Settlement Agreement. Intervenor IG Ex. 5 at p. 5. Because each sub-class of Tariff IP had a different percentage change in 12 demand units, primarily due to their respective power factors, the Settling Parties agreed to adjust the demand charges by an amount that roughly reflects that change. Mr. Dauphinais added that while this could not be done perfectly for all sub-classes without producing anomalous results that would encourage inefficiencies, the result is much closer to cost-of-service rate design than I&M's initial proposal. Intervenor IG Ex. 5 at p. 5. He testified the agreed rate design does not perfectly move all demand-related costs out of the energy charges for all sub-classes, but it is a fair result that reasonably balances the interests of pure cost-based rates with other factors taken into account in cost of service ratemaking; therefore, the result is consistent with basic principles of cost of service ratemaking. Intervenor IG Ex. 5 at p. 5.

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<sup>28</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.1.

<sup>29</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.3.

4. Tariff GS and Tariff LGS.<sup>30</sup> Mr. Williamson testified that I&M agreed to not combine Tariff LGS and Tariff GS base rates. Petitioner’s Ex. 15 at p. 36; Settlement Agreement Section I.B.4. I&M will continue to eliminate the kVA demand charge and Power Factor Correction Capacitor adjustment in Tariff LGS. To ease the transition from full kVA billing demands, I&M agreed to implement an excess kVA charge in Tariff LGS. Petitioner’s Ex. 15 at p. 36. Mr. Williamson shared the agreed tariff language and stated the rider rates for Tariffs LGS and GS were unified to mitigate some of the concerns that led I&M to initially propose combining the two tariffs.

5. Tariff Term and Condition No. 27.<sup>31</sup> Mr. Williamson stated the Settling Parties agreed I&M may adopt its new proposed Term and Condition No. 27 as modified in the Settlement Agreement. Petitioner’s Ex. 15 at pp. 36-37. He testified that although Petitioner does not agree that the concern the Industrial Group raised warrants rejection of I&M’s proposed provision, the Settling Parties resolved the dispute over the proposed change with the revised language Mr. Williamson provided. Petitioner’s Ex. 15 at p. 37.

Mr. Dauphinais stated his concern was the open-ended nature of the charge to large customers who request a disconnection/reconnection at a transformer, switch, or breaker. Mr. Dauphinais testified the modified language for Term and Condition No. 27 addressed these concerns with respect to the exposure of large customers to a potentially unknown charge without the ability to assess its reasonableness or alternatives to performing the work. Intervenor IG Ex. 5 at p. 4. He stated the Settlement Agreement provides for a “not to exceed” figure of \$1,500 to cover costs associated with such requests. Mr. Dauphinais added that for requests that are expected to exceed that amount, I&M has agreed to provide the customer with a binding estimate detailing the work and costs prior to the date work is to commence. Intervenor IG Ex. 5 at p. 4. This addresses his concerns with respect to the exposure of large customers. He noted the binding nature of the estimate also ensures there is some recourse for customers to the extent the cost of a disconnection/reconnection is disputed. Intervenor IG Ex. 5 at p. 4.

6. “Other Sources of Energy” Tariff Language.<sup>32</sup> In his direct testimony, Mr. Dauphinais also raised concerns regarding I&M’s proposal to strike language in Tariff IP related to the ability of customers with other sources of energy supply to take standby and backup service under that rate. Intervenor IG Ex. 5 at p. 4. Although I&M clarified in rebuttal its intent in striking the language, I&M agreed to retain this language in its tariffs for rates General Service – Tariff G.S. (“Tariff GS”), Large General Service – Tariff L.G.S. (“Tariff LGS”), Tariff IP, and Water and Sewage Service – Tariff 22 W.S.S. (“Tariff WSS”). He stated this ensures the ability of customers who self-supply power to access standby and backup service under specific rates will not be disputed, provided they qualify for the provision of service under those rates. Intervenor IG Ex. 5 at p. 4; *see also* Petitioner’s Ex. 15 at pp. 37-38.3

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<sup>30</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.B.4.

<sup>31</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.B.5.

<sup>32</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.B.6.

7. Critical Peak Pricing.<sup>33</sup> With respect to other rate design matters, the Settlement Agreement ensures that approval of the Critical Peak Pricing rate as part of this case does not represent approval to impose that rate on customers on an opt-out basis and that I&M must seek approval prior to any future opt-out rate approach. Mr. Eckert stated the Settlement Agreement also provides that I&M will address excluding holidays from high-rate periods in its next base rate case. Public's Ex. 15 at p. 15. Mr. Williamson stated this provision allows I&M to work through the technical issues associated with this approach.

**N. Remaining Issues.** Section I.C. of the Settlement Agreement provides that any matters the Settlement Agreement does not address will be as I&M proposed in its direct case.

In his Settlement testimony, Mr. Eckert pointed out that the Settling Parties did not oppose I&M's proposed ratemaking treatment for the Life Cycle Management ("LCM") Rider, explaining that I&M proposed the following: (1) to retire its LCM Rider; (2) to file its next LCM reconciliation (LCM 11) in the third quarter of 2021; (3) to make a compliance filing shortly after the order is received in this Cause; and (4) to address the final reconciliation of the LCM over/under recovery and on-going recovery of property tax expense on LCM investment made in 2022 in a subsequent ECR filing. Public's Ex. 15 at p. 10.<sup>35</sup>

**O. Supporting Documentation.** As Mr. Williamson explained, the Settlement Agreement includes as attachments a revised I&M Exhibit A-1, a breakdown of the approximately \$141 million of Rockport Unit 2 costs to be removed from I&M's proposed base rates, and the customer class allocations of the revenue requirement as agreed in the Settlement Agreement, including the impact of the Settlement Agreement on riders in Phase I and Phase II and the agreed Tariff IP rates. Petitioner's Ex. 15 at pp. 3-4.

The settlement testimony also includes Attachments AJW-1-S (updates to capital structure); AJW-2-S (depreciation rates); AJW-3-S (customer class revenue allocation factors, detailed base rate, rider, and total bill increase by class); AJW-4-S (typical bill comparison); AJW-5-S (forecasted test year end net plant balance used to calculate the Phase II rates); AJW-6-S (gross revenue conversion factor); AJW-7-S (updates Exhibit A-9 (Effective Federal Income Tax Rate)); AJW-8-S (Appendix G from IRS Internal Revenue Bulletin No. 2021-1); AJW-9-S (updated tariff book Table of Contents and Terms and Conditions of Service); and AJW-10-S (updated tariff book – tariffs and riders sections). Petitioner's Ex. 15 at pp. 4-5, 40. Workpapers updating the relevant cost of service and rate design were also provided.

**P. Phase-In Rate Adjustment and Compliance Filing.** In explaining the rate design associated with the proposed PRA factors under the Settlement Agreement, Mr. Williamson stated the Net Plant Credit was designed consistent with I&M's proposal in this filing and the calculation methodology utilized in prior I&M rate cases. He stated the rates for the other three components of the PRA were designed consistent with the methodology used for virtually all I&M riders, where costs were identified as either demand or energy-related and allocated to each class on demand or energy, respectively. Petitioner's Ex. 15 at p. 39. For each class, demand costs were

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<sup>33</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.7.

<sup>34</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.C.; *see also* Petitioner's Ex. 15 at p. 39.

<sup>35</sup> *See* Petitioner's Ex. 1, Attachment TLT-1 (Petition) and attached Ex. A for a list of I&M's original proposals.

generally collected through demand charges where possible (Tariffs IP, LGS, GS, and Electric Heating General) and otherwise through energy charges, and in all cases, energy costs were collected through energy charges. Mr. Williamson also reviewed what I&M anticipates filing as a compliance filing if the Settlement Agreement is approved. Petitioner's Ex. 15 at p. 41.

**Q. Typical Bill Comparison.** Mr. Williamson presented an updated typical bill comparison. For a typical residential customer using 1,000 kWh, the Phase I rates reflect a total monthly bill decrease of \$1.48 or 0.9%. For Phase II, the Settlement Agreement reflects an additional monthly bill decrease of \$7.95 or 5.1% at the end of the test year.

**R. Public Interest.** Mr. Williamson testified settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced, but the complexity of a rate case proceeding can make settlement challenging to achieve. He stated that in this case, the Presiding Officers set forth expectations in the procedural schedule that prompted the parties to commence settlement discussions in earnest so any settlement agreement and supporting testimony could be timely provided to allow the Commission sufficient opportunity for review. Mr. Williamson relayed that the Presiding Officers made themselves available on short notice so the parties could keep them informed and receive guidance upon settlement procedural matters. He stated this support as the parties worked to reach a global settlement was helpful and appreciated. Petitioner's Ex. 15 at p. 43.

Mr. Williamson opined that the Settlement Agreement is in the public interest and is supported by and within the scope of the evidence the Settling Parties presented. Taken as a whole, he stated the Settlement Agreement reasonably addresses the parties' concerns and provides a balanced, cooperative outcome upon the issues. He added the separate Muncie Settlement Agreement reasonably addresses the concerns Muncie raised and is also the product of arm's-length negotiations.

Mr. Eckert similarly testified that the Settlement Agreement balances the interests of I&M and ratepayers and will provide certainty regarding critical issues, including revenue requirements, authorized return, and the allocation of I&M's revenue requirement among its rate classes. Public's Ex. 15 at p. 2. He echoed that the Settlement Agreement is the product of intense negotiations, with each party offering compromise to challenging issues. While the Settlement Agreement balances all interests, Mr. Eckert testified that given the benefits provided to ratepayers under the Settlement Agreement, the OUCC believes the Settlement Agreement is a fair resolution, supported by the evidence, and should be approved. Public's Ex. 15 at p. 2.

Mr. Dauphinais testified the process of negotiating the Settlement Agreement brought I&M, the OUCC, the Industrial Group, and other intervenors together to reach compromise on a wide range of disputed issues. This required the parties to evaluate their positions and find common ground. While no party received the full measure of the positions espoused in their case-in-chief, he stated the total package represents a balancing of the parties' competing interests in favor of an overall result that is fair and reasonable. In his view, the Settlement Agreement represents the culmination of the parties' efforts to come together and through negotiations, reach a result that reflects the purpose of utility regulation — the balancing of interests between the utility and its consumers.

Both Messrs. Dauphinais and Gorman emphasized that the Settlement Agreement is the result of extensive effort by all the parties and their representatives to reach a reasonable final result. They testified the Settling Parties were able to negotiate compromises on complex issues in a collaborative fashion, and they opined that the resolution reflected in the Settlement Agreement will result in just and reasonable rates for I&M and consumers and that approval of the Settlement Agreement is in the public interest.

**8. Muncie Settlement Agreement.** Mr. Williamson summarized the concerns Muncie raised regarding its effort to develop a City-owned solar generating facility to be located on the former General Motors brownfield site in southwest Muncie, referred to in testimony as the “Chevy Plant”. Petitioner’s Ex. 15 at p. 42. He noted I&M witness Lucas in rebuttal apologized for the apparent confusion, clarified certain FERC requirements, and committed to I&M working with Muncie on this project and to providing clear information to help this project move forward. Petitioner’s Ex. 15 at p. 42. Mr. Williamson attached the Muncie Settlement Agreement to his settlement testimony as Attachment AJW-11-S.

Mr. Williamson testified the Muncie Settlement Agreement memorializes I&M’s commitment in substantial detail to assuage Muncie’s concerns and to clarify Petitioner’s role. He opined that the Muncie Settlement Agreement is in the public interest as it reasonably addresses the concerns Muncie raised and is the product of arm’s-length negotiations. Mr. Williamson noted the other parties to this proceeding are taking no position with respect to the issues addressed in the Muncie Settlement Agreement as the Muncie Settlement Agreement has no rate impact and does not affect any issues raised or presented in the Settlement Agreement. In their respective responses to Docket Entry questions posed on December 9, 2021, I&M and Muncie further address why the Muncie Settlement Agreement is in the public interest. Petitioner’s Ex. 45; Intervenor Muncie Ex. 3.

In its Docket Entry response, Muncie stated it has raised unique issues under the Commission’s broad authority provided under Ind. Code §§ 8-1-2-4 and 8-1-2.5-5 that are reasonably addressed in the Muncie Settlement Agreement. In his direct testimony, Mayor Ridenour testified the reason for Muncie’s participation in this matter was, in part, to provide details to the Commission so it could better understand how communities like Muncie depend upon and need a good, supportive relationship with their electric provider. He further explained how I&M is a necessary partner in Muncie’s ongoing challenge to retain and attract business and industry and the corresponding jobs that businesses provide. Intervenor Muncie Ex. 1 at p. 3. Mayor Ridenour noted that fundamental to Muncie’s efforts to retain and attract business and industry is continuing to make the proper investments and upgrades to electric infrastructure. He testified regarding the revitalization efforts Muncie is pursuing for the former Chevy Plant site to help jump-start growth, and he opined that these will benefit all of I&M’s customers and Muncie. For these reasons, Muncie stated in its Docket Entry response that the Muncie Settlement Agreement and the commitments and processes it memorializes are in the public interest. Intervenor Muncie Ex. 3 at p. 3.

In its Docket Entry response, I&M states that while I&M and Muncie agreed to support Commission approval of the Muncie Settlement Agreement, in I&M’s view the Commission could

accept the parties' agreed resolution and find either: (a) that the Muncie Settlement Agreement reasonably addresses and resolves their disputed issue or (b) that there is no remaining contested issue the Commission needs to address.

**9. Commission Discussion and Findings.** Settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced. The Settlement Agreement represents the Settling Parties' proposed resolution of the issues in this Cause. The Muncie Settlement Agreement represents I&M and Muncie's resolution of certain matters of concern to Muncie. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

Any Commission decision, ruling, or order, including approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's procedural rules require settlements to be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement or the Muncie Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that these agreements are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that such agreements serve the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement, including the Settling Parties' agreement on Petitioner's rate base, methodology to be used in determining Petitioner's rate decrease, agreed allocation of the decrease, agreed rate design, agreement on ROE and capital structure, and the other terms of the Settlement Agreement, all of which the Commission finds are supported by the settlement testimony and the additional Docket Entry responses. The Settlement Agreement is further supported by the Settlement Agreement attachments and the settlement schedules and workpapers. The Commission finds we have substantive information from which to discern the basis for the components of the decrease in I&M's base rates and charges and its reasonableness.

The Settlement Agreement resolves all the issues presented by I&M's Petition. To put this in context, I&M, in its initial case-in-chief filed in July 2021, supported a revenue deficiency of \$104 million, reflective of an overall 6.5% revenue increase. In contrast, as shown by Settlement Agreement Attachment 1, ln. 17, the Settling Parties agreed to a total revenue decrease of \$94.705 million, which is a 5.90% revenue decrease; however, I&M's case-in-chief increase did not include the removal of Rockport Unit 2 costs agreed upon in Cause No. 45546 that was recognized in arriving at the revenue decrease.

OUCG witness Eckert, in supporting approval of the Settlement Agreement, testified the consumer benefits from the Settlement Agreement include: (1) continuing the monthly residential customer charge of \$15.00; (2) no increase to I&M's current 9.70% ROE; (3) limiting I&M's debt

to equity ratio in its WACC to no higher than 50.00% equity; (4) an annual PJM NITS cost cap; (5) retention of approximately \$159 million in cost free capital that I&M proposed to remove from its capital structure through its NOLC adjustment, pending receipt of a PLR from the IRS; (6) removal of I&M's proposed \$69.3 million (Indiana jurisdictional) OPEB asset from I&M's rate base; (7) an agreed limitation on customer deposits to no more than \$50.00 for customers identified as LIHEAP participants or LIHEAP-eligible; and (8) additional benefits the Settling Parties negotiated. Public's Ex. 15 at pp. 5-6. As further discussed below, the Commission concurs that the Settlement Agreement, in balancing all interests, fairly resolves this proceeding, is supported by the evidence, and should be approved.

The evidence before the Commission supporting the Muncie Settlement Agreement is, as discussed below, significantly less substantial and was primarily elicited from Petitioner and Muncie via Docket Entry responses. Muncie filed no settlement testimony supporting this agreement although 170 IAC 1-1.1-17(d) states, "The settlement must be supported by probative evidence."

**A. Revenue Requirement.**

1. Return on Equity, Capital Structure, and Rate of Return.<sup>36</sup>

a. Return on Equity. The record reflects the agreed 9.70% ROE is within the range of evidence the Settling Parties presented and is the same ROE the Commission found to be fair and reasonable under the totality of the circumstances in I&M's last base rate case, Cause No. 45235 which was contested. The OUCC supported the agreed ROE as reasonable and in ratepayers' interest, noting the agreed ROE benefits ratepayers by reducing the return on rate base reflected in customers' rates as compared to I&M's proposal. The Commission finds that as part of the Settlement Agreement, the agreed ROE balances the consumer parties' concerns while preserving Petitioner's financial integrity and should, therefore, be approved.

b. Capital Structure. The Settling Parties agreed that for purposes of calculating the Phase-In Rate Adjustment for Phase I rates, the debt/equity ratio will be 50.54%/49.46% through the close of the test year. For purposes of Petitioner's Phase II compliance filing, they agreed the debt/equity ratio will be adjusted to the December 31, 2022, actual ratio based on shareholder contributions of debt and equity but will be no higher than a 50.00% equity ratio. Settlement Agreement Section I.A.1.f. Mr. Williamson testified this agreement resolves a concern Mr. Gorman raised when challenging the forecasted change in the ratio. Mr. Eckert testified there are ratepayer benefits associated with the agreed capital structure. Public's Ex. 15 at p. 7. The Commission finds the negotiated agreement regarding I&M's capital structure is reasonable, is within the range of outcomes the parties presented, resolves concerns the Industrial Group raised, and should be approved.

c. NOLC. As Mr. Williamson explained, the NOLC affects the calculation of ADFIT which is included as cost free capital in the capital structure. Petitioner's Ex. 15 at p. 9. I&M's understanding is that the NOLC needs to be accounted for in the ADFIT balance as a deferred tax asset ("DTA") to comply with the IRS normalization rules. Petitioner's Ex. 15 at

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<sup>36</sup> Joint Ex. 1 (Settlement Agreement) at Section I.A.1.a.

p. 9; therefore, Petitioner's filing included the NOLC DTA as part of the ADFIT to correct what I&M believes is an inconsistency to avoid a violation of the IRS normalization rules. Petitioner's Ex. 15 at p. 9. Mr. Williamson testified this approach has the effect of reducing the amount of cost free capital included in the capital structure. Some of the intervening consumer parties, however, contested I&M's conclusion regarding the normalization rules.

To resolve this issue, the Settling Parties agreed I&M will retain the approximately \$159 million in cost free capital that Petitioner proposed be removed per I&M's proposed NOLC adjustment pending receipt of a PLR from the IRS. Petitioner's Ex. 15 at p. 10. Mr. Williamson stated to avoid a normalization violation if the IRS agrees with I&M's position, it is important the contested amounts be preserved and Petitioner have the ability to timely recognize the impact in rates if the PLR confirms I&M's position; therefore, pending receipt of an IRS PLR, the Settling Parties agreed the Commission should authorize I&M to establish a regulatory asset for the return associated with including the proposed NOLC adjustment in the calculation of ADFIT in I&M's capital structure. Settlement Agreement Section I.A.1.b.i.; Petitioner's Ex. 15 at p. 10. The regulatory asset will also be established for the amount of any differences in I&M's requested levels of protected and unprotected EADFIT amortization (*see* Settlement Agreement Sections I.A.1.d. and I.A.1.e.) and the settled levels of amortization. Petitioner's Ex. 15 at p. 10. Mr. Williamson stated the accrual of this regulatory asset will have an effective date equal to the effective date of the rates being implemented in this proceeding. If the IRS PLR determines that failure to reinstate the proposed NOLC ADFIT in calculating I&M's capital structure constitutes a normalization violation, I&M will initiate a limited proceeding to update I&M's Tax Rider to reflect the NOLC adjustments, along with any Commission-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. I&M expects to implement this through a Tax Rider filing. Settlement Agreement Section I.A.1.b.ii. Mr. Williamson testified that if the IRS PLR determines there is no normalization violation created by not reinstating the NOLC ADFIT, the Settlement Agreement provides that the regulatory asset will be written-off and will not be recovered in rates. Settlement Agreement Section I.A.1.b.iii.; Petitioner's Ex. 15 at p. 11.

The Commission finds that with respect to NOLC, the Settling Parties have proposed a fair resolution as it provides customers the immediate benefit of a higher amount of cost-free capital in I&M's capital structure, while if the IRS finds a normalization violation would occur, the Settlement Agreement acknowledges the Settling Parties' right to challenge the continued benefit of I&M remaining in the AEP Tax Sharing Agreement on a going forward basis. *See* Intervenor IG Ex. 4 at p. 4; Petitioner's Ex. 15 at p. 11.

According to Mr. Williamson, during Petitioner's preparation of this case I&M discovered what I&M and its outside advisors believe is a normalization inconsistency which if not remedied will constitute a normalization violation. He stated that under the Internal Revenue Code ("IRC") safe harbor rules, this case is the "Next Available Opportunity" to correct this issue and avoid a potential normalization penalty. Petitioner's Ex. 15 at p. 9. The OUCC, IG, and the Joint Municipals do not agree a normalization issue exists. Public's Ex. 2 at p. 6; IG Ex. 1 at p. 37; Joint Municipal Ex. 2 at p. 4. The resolution proposed in the Settlement Agreement recognizes the IRS PLR process exists to allow the IRS to rule on matters regarding its tax rules; consequently, the Commission finds the Settlement Agreement provides a reasonable path forward to maintain an

unadjusted amount of zero cost capital pending potential clarification from the IRS regarding its normalization rules.

Accordingly, the Commission finds Section I.A.1. of the Settlement Agreement sets out a reasonable path for resolving the parties' differing perspectives upon the treatment of I&M's NOLC; therefore, the Commission approves the agreed NOLC treatment and grants I&M such accounting authority as necessary to implement the Settling Parties' related agreements.

d. Private Letter Ruling. As Messrs. Williamson and Eckert discussed, the Settling Parties negotiated a process that will allow the Settling Parties to have an opportunity to review the PLR request before it is submitted to the IRS and to be notified of any IRS requests for further information. Settlement Agreement Section I.A.1.c.; Petitioner's Ex. 15 at p. 11; Public's Ex. 15 at pp. 8-9. More specifically, under the Settlement Agreement the Settling Parties agree the IRS rules regarding normalization PLR requests contained in Appendix G of Internal Revenue Bulletin 2021-01 provide regulatory commissions and other interested parties certain participation rights in the PLR process. Per the Settlement Agreement, by agreeing to the terms of the settlement, the Settling Parties do not intend to limit the rights of the Commission, other interested parties, or noncompany Settling Parties from participating in the PLR process to the extent allowed under the IRS rules. Petitioner's Ex. 15 at pp. 11-12.

The record reflects American Electric Power ("AEP") has already initiated the PLR process for affiliates in other states. Petitioner's Ex. 15 at p. 12. If an AEP affiliate receives a PLR on this issue before I&M, I&M has agreed to provide the Settling Parties with a copy of the affiliate PLR, subject to a non-disclosure agreement, within ten business days. Petitioner's Ex. 15 at p. 12. Before I&M's PLR request is submitted to the IRS, I&M will provide a confidential draft of this PLR to the noncompany Settling Parties and will confer on a neutral description of the facts and Settling Parties' positions in the PLR request to objectively frame the issue while adhering to IRS guidelines and requirements. Under the Settlement Agreement, the noncompany Settling Parties will provide feedback to I&M on the draft PLR within five business days after receiving the PLR draft, and I&M will convene a virtual meeting to discuss this feedback on the sixth business day following transmittal to the noncompany Settling Parties.

The Settling Parties' negotiated process recognizes that as the signatory to the PLR, I&M will make the final determination upon the PLR contents but will also make good faith efforts to incorporate timely, reasonable feedback from the noncompany Settling Parties. Petitioner's Ex. 15 at p. 12. Meanwhile, the Settling Parties each retain their respective right to communicate with the IRS regarding the PLR as set forth in Internal Revenue Bulletin 2021-01 at page 103. Petitioner's Ex. 15 at p. 12; Attachment AJW-8-S (page 103). If the IRS requests additional information related to the PLR request, under the Settlement Agreement I&M will provide the noncompany Settling Parties with timely, meaningful notice of this IRS request before a response is due and provide a copy of I&M's response once made. Petitioner's Ex. 15 at p. 12. The Settlement Agreement also provides that Petitioner will file notice of the results of the ruling with the Commission and notify the Settling Parties within ten business days of receiving the PLR. Settlement Agreement Section I.A.1.c.iv.

Per the Settlement Agreement, no Settling Party will have waived any position in a subsequent case with respect to whether I&M may recover its costs associated with the PLR Request. Settlement Agreement Section I.A.1.c.v.; Petitioner's Ex. 15 at p. 13. To permit the Commission to make the necessary findings consistent with the terms of the Settlement Agreement, I&M has waived confidential treatment of: (1) the fact of its request for a PLR and (2) the overall results of the PLR. Settlement Agreement Section I.A.1.c.vi.; Petitioner's Ex. 15 at p. 13.

Based upon the settlement testimony, the Commission finds the Settlement Agreement provides a means to obtain a final resolution from the IRS on this issue while limiting Petitioner's financial risk if the IRS ultimately determines an adjustment to the treatment of EADFIT is necessary to avoid a normalization violation. Accordingly, the Commission finds the Settling Parties' negotiated process by which I&M will seek an IRS PLR is reasonable and should be approved; provided, I&M is directed to expeditiously initiate and complete the PLR filing process and confirm via a compliance filing under this Cause, within 14 days of this Order, the anticipated timeline associated with making this filing. Additionally, within ten business days of receiving the PLR, I&M is directed to file notice in this Cause of the results of the ruling and notify the Settling Parties consistent with the Settlement Agreement.

e. Tax Rider. Mr. Williamson testified the Commission's order in I&M's last rate case authorized I&M to implement the Tax Rider to address the ongoing rate impacts of TCJA. In this matter, I&M proposed to also use the Tax Rider to address any future changes in corporate federal income tax rates. This was opposed by multiple parties. The Settlement Agreement provides that the Tax Rider will serve only two purposes: (1) to credit customer rates for the remaining benefits associated with unprotected EADFIT as defined in the Settlement Agreement and (2) to implement ratemaking adjustments associated with an IRS PLR that requires I&M to make its proposed NOLC adjustment. Settlement Agreement Section I.A.1.d.; *see* Petitioner's Ex. 15 at pp. 13-14.

As explained by Mr. Williamson, simultaneous with implementing its new base rates, I&M will implement a Tax Rider to credit customer rates for the remaining benefits associated with unprotected EADFIT. Petitioner's Ex. 15 at p. 14. The Settling Parties also agreed to increase the amount of monthly amortization, Petitioner's Ex. 15 at p. 14, advancing the benefit of this amortization to customers. As a result, the amortization credit in the Tax Rider is expected to expire before the end of the test year. Petitioner's Ex. 15 at p. 14.

The Settlement Agreement further provides that for purposes of setting rates in this proceeding for the Tax Rider, I&M agrees not to adjust the remaining balance of unprotected EADFIT for any NOLC impact and agrees to a \$14,623,272 (Indiana jurisdictional) EADFIT credit as Joint Municipals witness Cannady proposed and a seven-month amortization period. Settlement Agreement Section I.A.1.d.; *see* Petitioner's Ex. 15 at p. 14. The total monthly EADFIT amortization to be credited to customers will be grossed up for taxes at a rate of 1.3580 and will include a carrying charge on the unamortized balance based on the pre-tax WACC approved in this proceeding. Per the Settlement Agreement, I&M will reconcile the Tax Rider to reflect its actual unprotected EADFIT amortization and the monthly remaining balance. Settlement Agreement Section I.A.1.d.; *see* Petitioner's Ex. 15 at p. 14.

The Commission finds the Settling Parties' agreement upon the scope of the Tax Rider and its implementation is reasonable and should be approved.

f. Net Operating Income. The Settling Parties agree I&M's authorized base rate net operating income will be \$296,733,906, calculated as follows:

Income Requirement	\$ 296,288,136
Remove Transmission Owner Costs, Revenues	\$ 605,355
Gross Revenue Conversion Factor	1.3580
After Tax	\$ 445,770
Total Base Rate Net Operating Income	\$ 296,733,906

Settlement Agreement Section I.A.1.g.; *see* Petitioner's Ex. 15 at pp. 15-16, Figure AJW-2. The Commission finds the agreed net operating income is reasonable and should be approved.

2. Rockport Unit 2 Costs.<sup>37</sup> Subsequent to I&M filing its case-in-chief, I&M and the other parties in Cause No. 45546 entered into a settlement agreement regarding the treatment of the Rockport Unit 2 costs after the lease ends. This agreement was approved by the Commission on December 8, 2021. Consistent with the Cause No. 45546 settlement agreement, the Settling Parties in this proceeding agreed to remove lease costs and all other costs and expenses associated with Rockport Unit 2 from rates.

As discussed by Mr. Williamson, the Settlement Agreement sets forth a process to efficiently achieve the agreed removal of Rockport Unit 2 costs. Petitioner's Ex. 15 at pp. 16-17. Under the Settlement Agreement, removal of Rockport Unit 2 costs from rates is achieved via the relevant tracking mechanisms. Petitioner's Ex. 15 at p. 17. Essentially, the Settling Parties agreed almost all costs related to Rockport Unit 2 will be removed from base rates immediately upon implementation of the new base rates associated with approval of the Settlement Agreement and recovered either through the riders by which they are already recovered or through a special charge included in the PRA Rider. Intervenor IG Ex. 4 at pp. 4-5. The direct costs of owning and operating Rockport Unit 2 will not be the responsibility of I&M's retail customers after the lease ends on December 7, 2022, per the settlement approved in Cause No. 45546. Prospectively, Unit 2 will be used to fulfill a small share of I&M's capacity needs through May 2024, but compensation for that service will be paid based upon PJM capacity market prices. Public's Ex. 15 at p. 7.

a. Phase I Base Rates. I&M agreed to remove from its base rates the revenue requirement of approximately \$141 million of Rockport Unit 2 costs, as identified in Settlement Agreement Attachment 2, at the time new base rates are implemented (Phase I). Settlement Agreement Section I.A.2.a.; *see* Petitioner's Ex. 15 at p. 16.

b. Phase-In Rate Adjustment. The Settling Parties agreed that upon implementation of new Phase I base rates, I&M will simultaneously implement a temporary

<sup>37</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.2.

charge through its PRA (*i.e.*, the “PRA Rockport Unit 2 Charge”), by which I&M will continue to recover the costs and expenses associated with Rockport Unit 2 that will not be tracked in other riders. Petitioner’s Ex. 15 at p. 17. More specifically, when I&M implements new base rates (Phase I) it will simultaneously implement the PRA, which will be computed based on two credits and one charge. Petitioner’s Ex. 15 at p. 17. The charge is to continue recovering Rockport Unit 2 related costs through the end of the lease or December 7, 2022; provided, that if I&M determines the PRA Rockport Unit 2 Charge has resulted in full recovery of Rockport Unit 2 costs before December 8, 2022, Petitioner shall cease collecting this charge. The PRA will be adjusted during the test year to remove the PRA Excluded Capacity Credit and PRA Rockport Unit 2 Charge according to the terms of the Settlement Agreement.

Per Section I.A.2.b. of the Settlement Agreement, the PRA Rockport Unit 2 Charge will include the following:

- i. A return on a fixed \$15,143,223 (Indiana jurisdictional) level of fuel and consumables inventory through December 7, 2022, at I&M’s Phase I WACC grossed up for taxes.
- ii. I&M’s recovery of the prorated share of a fixed \$1,035,878 (Indiana jurisdictional) annual level of fuel handling and disposal expenses through December 7, 2022.
- iii. I&M’s recovery of its Rockport Unit 2 lease expense incurred through the end of calendar year 2022, based on the prorated share of I&M’s annual \$48,924,630 (Indiana jurisdictional) lease expense. Since the PRA Rockport Unit 2 Charge will end on December 8, 2022, I&M’s Rockport Unit 2 lease expense will be grossed up to recognize the full annual lease expense for calendar year 2022 for purposes of setting the PRA Rockport Unit 2 Charge.
- iv. I&M’s recovery of the prorated share of a fixed \$13,240,324 (Indiana jurisdictional) annual level of other O&M expense (\$12,177,941) and property tax expense (\$1,062,383) through December 7, 2022.
- v. The revenue requirement for implementing the PRA Rockport Unit 2 Charge will be allocated and retail rates will be designed consistent with the Settling Parties’ agreed allocation methodology for demand and energy costs used in I&M riders to arrive at the agreed rider revenue allocation shown in Settlement Attachment 3.

Settlement Agreement Section I.A.2.b.; *see* Petitioner’s Ex. 15 at p. 18. Mr. Williamson testified this approach allows for the removal of the Rockport Unit 2 costs from the revenue requirement in a reasonable and efficient manner.

c. ECR and RAR. Section I.A.2.c. of the Settlement Agreement provides that upon the implementation of new Phase I base rates, I&M will simultaneously implement new ECR and RAR rates to continue recovering the Rockport Unit 2 costs and expenses currently recovered through those riders through the term of the lease. *See* Petitioner’s Ex. 15 at p. 19. I&M will make a filing in 2022 to revise its ECR and RAR rates to be effective with the first billing cycle in January 2023 to exclude the Rockport Unit 2 ECR and RAR costs that are no longer

recoverable after the end of the lease. The Settlement Agreement clarifies the Rockport Unit 2 related cost components of the ECR and RAR factors and how those costs will be treated in the future for ratemaking purposes.

Thus, the Settling Parties identified the costs that will be removed from base rates while maintaining recovery of these costs during the term of the Rockport Unit 2 lease and agreed upon an efficient process for implementing their agreement. Petitioner's Ex. 15 at p. 20. The Commission finds the negotiated settlement reasonably resolves the issues regarding these Riders.

d. Fuel. Section I.A.2.d. of the Settlement Agreement addresses the treatment of Rockport Unit 2 costs in I&M's FAC proceedings and sets out the base cost of fuel. The Settling Parties agree I&M will recover its actual Rockport Unit 2 FAC eligible fuel expenses incurred through December 7, 2022. I&M's base cost of fuel will include \$28,185,922 (total company), \$19,608,596 (Indiana jurisdictional), in embedded Rockport Unit 2 fuel costs that will serve as a proxy for I&M's replacement purchased power when Rockport Unit 2 is no longer used for retail energy needs. This amount is incorporated into I&M's fuel basing points of 13.110 mills per kWh, which will be reconciled to actual fuel costs in I&M's FAC proceedings. Petitioner's Ex. 15 at p. 21. Continuing to include Rockport Unit 2 fuel expense in I&M's FAC basing point recognizes that at times I&M will have to purchase power from PJM and allows for a basing point that reasonably recognizes the amount of energy that may be needed to serve I&M's Indiana customers. Petitioner's Ex. 15 at p. 21.

The Commission finds the agreed process provides for the removal of the Rockport Unit 2 costs from base rates in a reasonable and efficient manner. Among other things, the use of the PRA Rockport Unit 2 Charge avoids the need for I&M to prepare, and all the parties and the Commission to review, two sets of tariffs and associated compliance support. It provides an efficient and transparent approach for timely removal of these costs from base rates while maintaining recovery of these costs during the lease term. Accordingly, the Commission finds this provision of the Settlement Agreement is reasonable.

3. Remaining Rockport Unit 2 Net Book Value at December 7, 2022.<sup>38</sup> In Section I.A.3. of the Settlement Agreement, the Settling Parties resolve their differing views on I&M's recovery of the remaining Rockport Unit 2 net book value at the end of the lease by identifying the negotiated amount that will be recoverable and agreeing such recovery will occur on a levelized basis. When I&M makes its PRA compliance filing to implement final base rates (*i.e.*, Phase II), I&M will adjust the PRA to remove the remaining net book value of Rockport Unit 2 of \$77,687,384 (Indiana jurisdictional) from rate base. At that time and going forward through December 31, 2028, I&M will be permitted to recover a total of \$95,639,514 (Indiana jurisdictional) associated with the net book value of Rockport Unit 2, on a levelized basis, in I&M's ECR (or alternative rate adjustment mechanism if the ECR is discontinued). The final PRA compliance filing, to be made in January 2023, will result in final PRA tariff rates that will be applicable until I&M implements new base rates in its next general rate case. Petitioner's Ex. 15 at p. 22. The Commission finds this is a reasonable means to effectuate the recovery of the remaining Rockport Unit 2 net book value at the end of the lease.

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<sup>38</sup> Joint Ex. 1 (Settlement Agreement) at Section I.A.3.

4. Jurisdictional Reallocation.<sup>39</sup> The OUCC, IG, and Joint Municipals took the position that the excluded capacity adjustment the Commission ordered in Cause No. 45235, or some version of that adjustment, should continue at least until the Rockport Unit 2 lease ends on December 7, 2022, at which point I&M will no longer have the excess capacity that supported the Commission's prior decision. In its rebuttal, I&M contested this position, contending Petitioner needs to meet its PJM capacity obligation as of June 1, 2022, and that is the time I&M will be short the capacity necessary to meet that obligation, absent other arrangements. Petitioner's Ex. 14 at p. 16.

The negotiated settlement resolves this issue by I&M agreeing to temporarily reflect in ratemaking the effect of the excluded capacity from Cause No. 45235, beginning with the implementation of new base rates (Phase I) in this Cause through December 7, 2022, via the proposed PRA Excluded Capacity Credit. Settlement Agreement Section I.A.4. Per Mr. Williamson, I&M will implement Phase I rates and simultaneously implement a temporary PRA Excluded Capacity Credit to credit customers for excluded capacity costs consistent with the 45235 Order, with the credit eliminated from the PRA on a service-rendered basis effective December 8, 2022. Petitioner's Ex. 15 at p. 23. The credit will be developed based on a monthly amount of \$4,702,533 offset by the fixed annual level of retained capacity and Off System Sales revenues of \$24,926,096, prorated to a monthly level of \$2,077,175, for a net monthly credit of \$2,625,358. Petitioner's Ex. 15 at p. 23. I&M will revise the PRA to remove the PRA Excluded Capacity Credit by submitting a compliance tariff to the Commission in this Cause. Since this change will fully eliminate this component, and the impact to the PRA is limited to the calculations associated with removing this component of the PRA factors, I&M asks the Commission to expeditiously approve the revision. Petitioner's Ex. 15 at p. 23.

IG witness Gorman testified Section I.A.4. of the Settlement Agreement fairly reflects adherence to the 45235 Order during most of the test year and the change that will occur in I&M's capacity position after December 7, 2022, when the Rockport Unit 2 lease expires. Intervenor IG Ex. 4 at p. 4.

The Commission finds the negotiated agreement regarding the treatment of the excluded capacity reasonably resolves this issue. The Commission further finds I&M's proposal to submit a compliance tariff in this docket (Cause No. 45576) to eliminate the PRA Excluded Capacity credit from the PRA factors is acceptable.

5. PJM NITS Costs.<sup>40</sup> Section I.A.5. of the Settlement Agreement balances I&M's need for timely cost recovery of PJM NITS costs with the Industrial Group's interest in understanding the investments underlying the PJM rate adjustment mechanism. Petitioner's Ex. 15 at p. 24. The Commission finds the negotiated compromise establishes a defined cap on increases between general rate cases. Under the Settlement Agreement, I&M will provide the same annual presentation to noncompany Settling Parties on a going forward basis that has previously been provided to the Michigan Public Service Commission. This will provide additional detail regarding supplemental projects consistent with the information provided through the PJM stakeholder process. Settlement Agreement Section I.A.5.

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<sup>39</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.4.

<sup>40</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.5.

As agreed by the Settling Parties, an annual cap will be placed on the PJM NITS costs recorded to FERC accounts 4561035 and 5650016 and recovered through the Off System Sales/PJM (“OSS/PJM”) Rider at I&M’s Indiana jurisdictional amount forecasted for 2024, plus 15%, which totals \$381.3 million (Indiana jurisdictional). Settlement Agreement Section I.A.5. These are the same FERC accounts that were reflected in the settlement agreement approved in Cause No. 44967. Petitioner’s Ex. 15 at p. 24. If annual NITS costs recorded to FERC accounts 4561035 and 5650016 exceed \$381.3 million in any year, I&M will defer to a regulatory asset the revenue requirement associated with the excess amount, including ongoing carrying costs at the pre-tax WACC, for recovery in I&M’s next base rate case. The remaining NITS costs up to the annual cap level will continue to be recovered through I&M’s OSS/PJM Rider, and all other costs and revenue credits will be included in the OSS/PJM Rider as I&M proposed. Petitioner’s Ex. 15 at p. 24.

The record reflects PJM NITS are a significant expense borne by I&M’s customers. As Mr. Dauphinais observed, PJM NITS costs are forecasted to continue to increase; consequently, an annual cap helps ensure customers face a limit on these increases in any given year. Intervenor IG Ex. 5 at p. 3. The Commission finds the agreed annual cost cap provides flexibility, allowing I&M to recover costs over or under its annual forecasted amounts, plus an additional 15%, while limiting the PJM NITS cost recovery from ratepayers through the PJM Rider during the designated period. For I&M, the creation of a regulatory asset including carrying costs reduces uncertainty regarding future cost recovery of amounts in excess of the annual cap and recognizes the time value of money impact of the delayed recovery. Based on the settlement testimony, the Commission finds the Settling Parties’ agreement with respect to the treatment of PJM NITS costs is a reasonable compromise and within the range of outcomes the evidence supports.

6. AMI.<sup>41</sup> In its case-in-chief I&M included an AMI in-service investment through the end of the test year in rate base and sought approval of the AMI deployment and authority to implement an AMI Rider to track post test year investment.<sup>42</sup> Other parties opposed the AMI Rider.<sup>43</sup> In the Settlement Agreement, the Settling Parties agreed to include I&M’s capital forecast period (2021-2022) AMI capital of \$54.649 million and O&M costs of \$4.77 million in the base rates set in this Cause. Settlement Agreement Section I.A.6. I&M agreed to withdraw its request for an AMI rider. Under the Settlement Agreement I&M is not prevented from seeking recovery of additional AMI investment and O&M costs in its next base rate case(s), and the noncompany Settling Parties agree to not challenge the reasonableness of I&M’s transition from AMR meters to AMI meters or the reasonableness of I&M’s four-year deployment plan, as presented in this Cause, in a future proceeding. Settlement Agreement Section I.A.6. I&M also agreed to notify its customers about Petitioner’s ability to remotely disconnect customers with AMI meters. Public’s Ex. 15 at p. 12. The Commission finds this agreement resolves the AMI deployment question, provides a reasonable level of ratemaking support and assurance with respect to I&M’s proposed AMI program, and is generally consistent with our approval in I&M’s last rate case.

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<sup>41</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.A.6.

<sup>42</sup> Petitioner’s Ex. 2 at pp. 36-40; Petitioner’s Ex. 7 at pp. 34-41.

<sup>43</sup> Public’s Ex. 5 at pp. 4-10; Public’s Ex. 11 at pp. 9-11, Jt. Municipals Ex. 2 at pp. 23-26.

7. Rate Base.<sup>44</sup> In its case-in-chief, I&M's proposed rate base was identified in Petitioner's Ex. 43 (Financial Exhibit A), Exhibit A-6. Other parties challenged including the prepaid pension and OPEB assets in rate base, as well as certain aspects of I&M's distribution investment plan.<sup>45</sup> The Settlement Agreement provides for reductions to I&M's test year rate base. As discussed below, the Commission finds the agreed provisions reasonably resolve the contested issues while recognizing ongoing capital investment is necessary to maintain safe, reliable, efficient, and environmentally compliant service.

a. Pre-Paid Pension and OPEB Assets. The prefiled testimony demonstrates the dispute regarding the OPEB and Pre-Paid Pension Assets. Mr. Williamson and OUCC witness Eckert testified that in the Settlement Agreement, the Settling Parties agree rate base will include the pre-paid pension asset in the amount of \$80.7 million (total company), \$58.1 million (Indiana jurisdictional), and to the removal of \$96,252,892 (total company), \$69,324,472 (Indiana jurisdictional) OPEB prepayment asset from rate base. Petitioner's Ex. 15 at p. 26; Public's Ex. 15 at pp. 12-13.

The Commission has previously approved inclusion of a prepaid pension asset in I&M's rate base in Cause Nos. 44075, 44967, and 45235. The Commission finds the Settlement Agreement compromise reasonably resolves the parties' differing views upon the treatment of the Pre-Paid Pension and OPEB Assets.

b. Non-Rockport Unit 2 Miscellaneous Rate Base Adjustments. Section I.A.8. of the Settlement Agreement reflects that for purposes of calculating the revenue requirement used to set base rates, I&M will reduce its proposed rate base by \$26.4 million. This reduction consists of: (1) \$3,783,088 in EV Fast Charging costs; (2) \$568,770 Flex Pay Program costs; (3) \$2,023,141 unamortized COVID-19 deferred bad debt expense; and (4) \$20 million of forecasted distribution plant investment. The Settlement Agreement provides that nothing in the agreement precludes I&M from seeking to include the removed items in its cost of service in a future case. Settlement Agreement Section I.A.8. The Commission finds the negotiated agreement regarding miscellaneous rate base adjustments reasonably resolves the related concerns raised in this proceeding.

8. Depreciation Rates.<sup>46</sup> The Settlement Agreement provides for a \$10 million reduction in depreciation expense but otherwise does not change I&M's proposals regarding depreciation, including the proposal to determine I&M's depreciation expense for the Rockport Plant as a whole. Settlement Agreement Sections I.A.9.a. and I.C. Proposed depreciation rates that implement the agreed \$10 million expense reduction were provided in Petitioner's Ex. 15, Attachment AJW-2-S. The Commission finds the Settling Parties' agreements upon depreciation expenses are reasonable, including I&M's proposal to determine its depreciation expense for the Rockport Plant as a whole, and should be approved.

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<sup>44</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.7. and 8.

<sup>45</sup> Public's Ex. 2 at pp. 52-62; Intervenor IG Ex. 2 at pp. 24-31.

<sup>46</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.9.a.

9. Other Operating Expense Adjustments As Messrs. Williamson and Eckert testified, the Settling Parties also agreed to adjustments to test year expenses. Petitioner's Ex. 15 at p. 28; Public's Ex. 15 at p. 13. This agreement does not, however, preclude I&M from seeking recovery of these types of expenses in a future case. Settlement Agreement Section I.A.9. These adjustments reduce I&M's revenue deficiency and provide savings to customers. As discussed below, the Commission finds these terms of the Settlement Agreement are within the range of the evidence and reasonably resolve the contested issues related to these expenses.

a. Nuclear Decommissioning. The parties contested whether nuclear decommissioning funding should remain at its current level as I&M originally proposed or be reduced to zero as the OUCC proposed.<sup>48</sup> The Settlement Agreement provides for a \$2 million decrease in nuclear decommissioning expense. Settlement Agreement Section I.A.9.b. The Settling Parties agree that I&M may seek to adjust the funding level of the Nuclear Decommissioning Trust based on future analysis of its adequacy to pay for decommissioning. The Commission finds this reasonably balances the consumer party concerns that the Nuclear Decommissioning Trust Fund is already adequately funded with I&M's concern regarding the potential for a shortfall.

b. Deferred COVID-19 Bad Debt Expense. The Settling Parties accepted OUCC witness Blakley's proposal to reduce the incremental COVID-19 bad debt expense amortization by \$293,773. Settlement Agreement Section I.A.9.c.; *see* Petitioner's Ex. 15 at p. 28, Public's Ex. 15 at p. 13. Mr. Williamson stated that while I&M disagrees with the basis for the OUCC's proposed adjustment, in the context of the overall settlement, Petitioner accepted this proposal as part of the goal of mitigating the impact of this case on customer rates. Petitioner's Ex. 15 at p. 28. The Commission finds this compromise reasonably resolves this contested issue.

c. Other Test Year O&M. The Settlement Agreement provides for an additional \$4 million reduction in test year O&M. Settlement Agreement Section I.A.9.d. This provision recognizes that other aspects of I&M's test year O&M forecast were challenged. Mr. Williamson testified Petitioner stands behind its forecasting process, but in the spirit of compromise, I&M agreed to reduce forecasted O&M by \$4 million. Petitioner's Ex. 15 at p. 28. The Commission finds this reasonably resolves the issue regarding test year O&M and is within the scope of the evidence the parties presented.

10. Other Provisions.<sup>49</sup> Additional provisions of the Settlement Agreement are addressed below.

A. OUCC Report in FAC. As discussed by Messrs. Williamson and Eckert, I&M agreed to the OUCC prospectively having a 35-day review period in Petitioner's FAC proceedings, starting with Cause No. 38702 FAC 89, which I&M expects to file in late July 2022 or early August 2022. Settlement Agreement Section I.A.10.a.; Petitioner's Ex. 15 at p. 29; Public's Ex. 15 at p. 10. While I&M has historically disputed the need for this lengthened review, the OUCC has raised the issue before, and per Mr. Eckert, the OUCC believes a 35-day review

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<sup>47</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.9.b-d.

<sup>48</sup> Petitioner's Ex. 21 at pp. 4-24; OUCC Ex. 1 at pp. 11-14.

<sup>49</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.A.10.

period is necessary to provide the OUCC adequate time to review I&M's six-month FAC filing and issue appropriate discovery to evaluate and address any issues. Public's Ex. 15 at p. 10. The Commission finds the Settling Parties' agreement upon this 35-day review period is reasonable and should be approved.

**B. Vegetation Management.** I&M agreed to include vegetation management reliability statistics in its Cause No. 44967 performance metrics report. Settlement Agreement Section I.A.10.b. As discussed in the rebuttal testimony of I&M witness Isaacson, Petitioner already reports its annual level of vegetation management investment and SAIDI statistics from tree-related outages in this report. Petitioner's Ex. 8 at p. 3; Petitioner's Ex. 15 at p. 30. The Settlement Agreement accepts OUCC witness Eckert's recommendation that I&M add to this report System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") statistics for tree-related outages. Petitioner's Ex. 15 at p. 30. The Commission finds this additional information will assist the Commission and interested stakeholders in monitoring I&M's vegetation management program, and SAIFI and CAIDI statistics for tree-related outages should, therefore, be added to I&M's reporting as agreed. We note that while I&M demonstrated a 30% decrease in SAIDI outages, continued improvement from this program is important, and these additional reliability statistics should aid in analyzing this progress.

**C. Notification of Disconnection of Service.** As part of the Settlement Agreement, I&M agreed to notify its customers via bill insert, text, and email of I&M's ability to remotely disconnect/reconnect. Settlement Agreement Section I.A.10.c. This notice shall identify a customer's rights prior to disconnection, including a description of the process I&M will use when attempting to contact its customers before a remote disconnection, and provide information on how to contact I&M's customer service department and LIHEAP. The notice will also provide information on how to add an email address and/or mobile phone number to receive Petitioner's notifications. The record shows the OUCC did not oppose I&M's remote disconnect/reconnect rule waiver request, subject to the OUCC's recommendation regarding customer notification. Petitioner's Ex. 4 at pp. 35-36. The Commission finds the negotiated compromise in the Settlement Agreement reasonably balances the consumer parties' interest in affording customers additional notice with the need for such communications to be issued effectively and efficiently.

**D. Solar Power Rider.** As part of the Settlement Agreement, I&M agreed to withdraw its request to change the name of the Solar Power Rider and to not make related tariff language modifications. Settlement Agreement Section I.A.10.d. This resolves the concern the Joint Municipals raised as to the purpose of I&M's original name change proposal. This agreement is without prejudice to seek a name change and related tariff language modifications in a future proceeding. The Commission finds these agreements reasonably mitigate controversy in this rate case while preserving I&M's option to make this proposal in the future.

**E. Flex Pay Program.** As part of the negotiated settlement, I&M agreed to withdraw its request to implement the Flex Pay Program without prejudice to seek approval of such a program in the future. Settlement Agreement Section I.A.10.e. If I&M pursues such a prepaid program in the future, I&M agreed its proposal will reflect that Petitioner will (i) not market to customers facing disconnection for non-payment or customers concerned about the

deposit amount required by I&M; (ii) market the program as a voluntary service; and (iii) ensure customers can purchase service credits 24 hours per day, seven days per week via phone or internet with no transaction fees. Settlement Agreement Section I.A.10.e. I&M also agreed to meet with interested stakeholders, including CAC, prior to again filing for this program to receive input on the development of the program, including concerns related to the winter disconnection moratorium under Ind. Code § 8-1-2-121. Petitioner's Ex. 15 at pp. 31-32. The Commission finds this resolution reasonably affords I&M the opportunity to gather stakeholder input that may reduce or avoid controversy in a future proceeding.

**F. Electric Vehicle Fast Charging Program.** As part of the Settlement Agreement, I&M agreed to withdraw its request to implement the EV Fast Charging program, without prejudice to seek approval for such a program in the future. Settlement Agreement Section I.A.10.f. The Commission finds this will enable I&M to gather and further consider stakeholder input in designing this program, Petitioner's Ex. 15 at p. 32, and reasonably resolves this issue.

**G. I&M-funded Customer Benefits.** In Section I.A.10. of the Settlement Agreement, I&M agreed to make certain contributions to various customer programs that are excluded from I&M's cost of service used to determine rates. Public's Ex. 15 at p. 11; Petitioner's Ex. 15 at pp. 32-34. More specifically, I&M agreed to fund \$175,000 per year in 2022 and 2023 to continue the low-income arrearage forgiveness program currently in place as a result of the settlement agreement in Cause No. 44967 and to exclude these costs from I&M's cost of service. Settlement Agreement Section I.A.10.g. This funding is responsive to CAC witness Howat's proposal for low-income customer assistance, including an arrearage management component. CAC Ex. 1 at p. 15; Petitioner's Ex. 15 at pp. 32-33.

I&M also agreed that customer deposits for customers identified as LIHEAP participants or LIHEAP-eligible will not exceed \$50.00. Settlement Agreement Section I.A.10.h. This is responsive to the recommendation Mr. Howat made based on his view that a large deposit for new or restored service can be extremely burdensome for income qualified customers. CAC Ex. 1 at p. 23; Petitioner's Ex. 15 at p. 33. According to Mr. Williamson, this commitment will allow I&M to gain insight regarding how to help customers who are challenged to pay their electricity bill. In its docket entry responses, I&M stated that to the extent the deposit for LIHEAP customers is capped at \$50.00, this may also mitigate the cost of collection, bad debt expense, and the associated cost of customer support, benefitting all customers going forward because such costs are reflected in the retail revenue requirement used to establish rates. In addition, because all consumers are at risk of financial hardship, I&M averred that the proposed deposit cap is a reasonable additional means of facilitating and exploring home energy security.

I&M will also provide a \$150,000 contribution to the community action program network of the Indiana Community Action Association to facilitate low-income weatherization in I&M's service territory including, but not limited to, using funds to address health and safety issues preventing weatherization and to assist in bill payment and deposit assistance for I&M LIHEAP eligible households. Settlement Agreement Section I.A.10.i. I&M's cost of service in this Cause is not being adjusted to include the incremental costs of this contribution. Settlement Agreement Section I.A.10.i. Additionally, I&M agreed to contribute \$100,000 to the Indiana Utility Ratepayer Trust. Settlement Agreement Section I.A.10.j. Petitioner's cost of service in this Cause is also not

being adjusted to include the incremental cost of this contribution. The Commission finds the contributions and programs agreed upon in the Settlement Agreement were shown to provide benefits for I&M and/or its customers and are reasonable as part of the negotiated settlement.

## **11. Cost of Service and Rate Design.**<sup>50</sup>

**A. Revenue Allocation.**<sup>51</sup> Section I.B.2 of the Settlement Agreement sets forth the Settling Parties' agreement that rates be designed to allocate the revenue requirement to and among I&M's customer classes in a fair and reasonable manner. The Settlement Agreement Attachment 3 specifies the revenue allocation the Settling Parties agreed to. Petitioner's Ex. 15 at p. 35. Per the Settlement Agreement, this revenue allocation is strictly for settlement purposes and is without reference to any specific cost allocation methodology. Mr. Williamson's Attachment AJW-3-S (Public) updates Attachments JLF-2 and JLF-3 to reflect the Settlement Agreement and provides supporting details, including the customer class revenue allocation factors and detailed base rate, rider, and total bill increase by class.

Mr. Eckert testified the Settling Parties negotiated a fair and reasonable revenue class allocation to allocate the costs of service among all rate classes, Public's Ex. 15 at p. 13, with the OUCC concluding it is a fair compromise. Mr. Dauphinais testified the Settlement Agreement includes an agreed revenue allocation that is without reference to any specific allocation methodology and, therefore, the Commission is not being asked to make findings upon any specific allocation methodology. He stated that given the difference of opinions among the Settling Parties on the proper method of cost allocation, he believes this is an important term that reflects the Settling Parties' overall efforts to put aside their differences to arrive at a result that is within the range of outcomes presented in the evidence and is a fair allocation of the overall revenue requirement among the various rate classes.

The record reflects the Settling Parties negotiated and resolved their differences with respect to the method of cost allocation through the Settlement Agreement. Settlement Agreement Section I.B.2. The Commission finds the Settling Parties' agreement with respect to the revenue allocation is within the range of outcomes the evidence supports and is reasonable.

**B. Residential Rate Design.**<sup>52</sup> Mr. Williamson testified that while I&M has firmly held positions regarding the application of cost of service and cost recovery principles to residential rate design, I&M also recognizes the passion this issue evokes. He stated the divergence of views made this issue challenging to resolve. Ultimately, the Settling Parties agreed to small changes to the rate design the Commission approved in I&M's last basic rate case. More specifically, Mr. Williamson stated the Settling Parties agreed to keep I&M's fixed monthly charge for Residential Electric Service - Tariff R.S. ("Tariff R.S.") at \$15.00. Settlement Agreement Section I.B.1; Petitioner's Ex. 15 at p. 35. The Settling Parties also agreed the fixed monthly charge for Residential Time-of-Day Service (Tariff R.S.-TOD and Tariff R.S.-TOD2) will increase to \$17.00. Settlement Agreement Section I.B.1; Petitioner's Ex. 15 at p. 35.

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<sup>50</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.

<sup>51</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.2.

<sup>52</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.1.

Mr. Eckert testified the OUCC's longstanding position is that a residential customer charge should not reflect more than the direct cost of connecting a customer to the distribution system from the standpoint of economic efficiency and regulatory policy. Public's Ex. 15 at p. 14. He noted that in its direct case, I&M proposed a 33% or \$5.00 increase in the residential fixed charge from \$15.00 to \$20.00, but through compromise, the Settling Parties agreed to maintain the monthly customer charge of \$15.00 for Rate RS.

The record demonstrates residential rate design issues were the subject of much testimony and that the monthly customer charge was the subject of deliberate negotiations. Petitioner's Ex. 15 at p. 34; Public's Ex. 15 at p. 14. Under the Settlement Agreement, I&M's Tariff R.S. residential customer charge will remain at \$15.00 per month, and the fixed monthly customer charge for residential Time-of-Day Service will increase to \$17.00. Settlement Agreement Section I.B.1. This more gradual movement in the fixed charge for residential Time-of-Day Service and maintenance of the current fixed charge for most residential customers are supported by the evidence and resolve these disputed issues. The Commission, therefore, finds the negotiated compromise upon the residential rate design is reasonable.

### **C. Commercial and Industrial Rate Design.**

1. Tariff IP Design.<sup>53</sup> The Settling Parties agreed to a Tariff IP rate design that produces agreed energy and demand charges as set out in Settlement Attachment 3. Settlement Agreement Section I.B.3. To correspond with acceptance of I&M's proposed change in Tariff IP billing demands from kVA to kW, the settlement demand charges were increased to reflect the approximate average power factor (kW per kVA) for each voltage level of Tariff IP. Consistent with this change, the reduced amount of residual demand-related costs includes the first 410 kWh per kW energy block. *See* Petitioner's Ex. 15 at p. 36.

In supporting the settlement, Mr. Dauphinais testified that in his direct testimony he raised concerns with I&M's proposed design for Tariff IP. He was concerned that I&M proposed to shift demand-related costs into the first block energy charge as a result of a shift from kVA billing demand to kW billing demand units, a shift that resulted, due to the conversion factor, in a reduction of billing determinants from which to collect demand-related charges. Mr. Dauphinais proposed that all demand-related costs be removed from the energy charges and placed back into the demand charges. He stated this is essentially what was done in arriving at the rates included in the settlement. Because each sub-class of Tariff IP had a different percentage change in demand units, primarily due to their respective power factors, the Settling Parties agreed to adjust the demand charges by an amount that roughly reflected that change. While this could not be done perfectly for all sub-classes without producing anomalous results that would encourage inefficiencies, he testified the result is much closer to cost-of-service rate design than I&M's initial proposal. Intervenor IG Ex. 5 at p. 5. Mr. Dauphinais added that while the design does not perfectly move all demand-related costs out of the energy charges for all sub-classes, it is a fair result that reasonably balances the interests of pure cost-based rates with other factors that are considered in cost-of-service ratemaking.

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<sup>53</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.3.

The Commission finds the agreed change in rate design for Tariff IP is a reasonable alignment of the change in billing units with the change in rates and should be approved.

2. Tariff GS and Tariff LGS.<sup>54</sup> In its case-in-chief, I&M proposed to consolidate Tariff GS and Tariff LGS into one tariff to provide flexibility to address changes in general service customer load without requiring customers to move back and forth between tariffs. Petitioner's Ex. 37 at p. 21. In the Settlement Agreement, I&M agreed not to combine Tariff GS and Tariff LGS, but Petitioner will eliminate the kVA demand charge and Power Factor Correction Capacitor adjustment in Tariff LGS. Settlement Agreement Section I.B.4. To ease the transition from full kVA billing demands, I&M agreed to implement an excess kVA charge in Tariff LGS. The specific language of the Excess kVA provision is as follows:

The monthly KVA demand shall be determined by dividing the maximum metered KW demand by the average monthly power factor. The excess KVA demand, if any shall be the amount by which the monthly KVA demand exceeds the greater of (a) 101% of the maximum metered KW demand or (b) 60 KVA. The Metered Voltage adjustment, as set forth below, shall apply to the customer's excess KVA demand.

Petitioner's Ex. 15 at p. 36. In addition, the rider rates for Tariffs GS and LGS were unified to mitigate some of I&M's concerns that prompted its initial proposal to combine Tariff GS and Tariff LGS.

The Commission finds the Settling Parties' negotiated compromise regarding the rate design for Tariffs GS and LGS reasonably resolves these matters.

3. Tariff Term and Condition No. 27.<sup>55</sup> The Settling Parties agreed I&M may adopt a new provision in its Terms and Conditions as set forth below:

27. Customer Requested Disconnection / Reconnection at Station Transformer. Whenever, at the customer's request, the Company is required to perform a disconnection and / or reconnection at a customer or Company owned station transformer, switch or breaker, the customer shall reimburse the Company for the entire cost incurred in making such connections which shall include all labor costs, transportation and equipment costs and any materials used not to exceed \$1,500. In the event that such costs are expected to exceed \$1,500, the Company shall provide the Customer with a binding estimate detailing the scope of work and associated costs to perform such work prior to the date on which the work is scheduled to commence.

Settlement Agreement Section I.B.5; Petitioner's Ex. 15 at pp. 36-37. Mr. Williamson testified that although I&M does not agree the concern the Industrial Group raised warranted rejection of I&M's proposed provision, the Settling Parties resolved these matters through the above revised language. Petitioner's Ex. 15 at p. 37.

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<sup>54</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.4.

<sup>55</sup> Settling Parties' Joint Ex. 1 (Settlement Agreement) at Section I.B.5.

Mr. Dauphinais testified the Settlement Agreement resolves his concerns with respect to the exposure of large customers to a potentially unknown charge without the ability to assess its reasonableness or alternatives to performing the work. He stated the binding nature of the estimate also ensures there is some recourse for customers to the extent the cost of a disconnection/reconnection is disputed. Intervenor IG Ex. 5 at p. 4.

The Commission finds the Settlement Agreement provision regarding Tariff Term and Condition No. 27 reasonably resolves the concerns raised.

4. “Other Sources of Energy” Tariff Language.<sup>56</sup> In his direct testimony, Mr. Dauphinais questioned I&M’s proposal to strike language in Tariff IP related to the ability of customers with other sources of energy supply to take standby and backup service under that rate. Although I&M clarified in rebuttal its intent in striking this language, Petitioner agreed in the Settlement Agreement to retain that language in Tariffs GS, LGS, IP, and WSS. Settlement Agreement Section I.B.6. Mr. Dauphinais testified this ensures the ability of customers who self-supply power to access standby and backup service under specific rates will not be disputed, provided they qualify for service under those rates.

Mr. Williamson testified a copy of the revised language is included in the Special Terms and Conditions provision of each of the identified tariffs in Attachment AJW-10-S. Petitioner’s Ex. 15 at p. 37. He stated this change clarifies I&M’s intent with respect to the language change. Petitioner’s Ex. 15 at pp. 37-38.

The Commission finds this provision of the Settlement Agreement is a reasonable resolution of the concerns raised.

5. Critical Peak Pricing.<sup>57</sup> I&M witness Walter explained in his rebuttal testimony why I&M disagreed with the OUCC’s proposal related to I&M’s proposed Critical Peak Pricing program. Petitioner’s Ex. 18 at pp. 20-21. After discussing this issue further, as part of the Settlement Agreement I&M agreed to propose provisions in its next base rate case addressing the exclusion of holidays from the days for which Critical Peak Events may be called. Settlement Agreement Section I.B.7. This allows I&M to work through the technical issues associated with this approach. In addition, Settlement Agreement Section I.B.7. sets forth the Settling Parties’ agreement that I&M is not receiving authorization for Tariff R.S. – Critical Peak Pricing as an opt-out rate in this proceeding and must obtain Commission approval for any opt out rate provisions prior to implementation. Petitioner’s Ex. 15 at p. 38. The Commission finds this reasonably resolves the concern OUCC witness Boerger raised.

**D. Remaining Issues.** Under Section I.C. of the Settlement Agreement, any matters not addressed by the Settlement Agreement will be adopted as proposed by I&M. This type of provision is common in settlement agreements before the Commission to help assure all matters are addressed. While the Commission will not review with specificity the totality of what this provision covers, we note this will maintain the I&M Major Storm Damage Reserve, accepts

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<sup>56</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.B.6.

<sup>57</sup> Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.B.7.

I&M’s proposal to wind down the LCM Rider in an efficient manner, and includes the PJM Capacity Performance Insurance expense in the cost of service.<sup>58</sup> Under this provision, I&M’s request for authority to accelerate recovery of noncurrent SO<sub>2</sub> allowances is also, effectively, accepted.<sup>59</sup> The Commission finds Section I.C. of the Settlement Agreement is reasonable; therefore, the Commission grants I&M’s request for authority to accelerate recovery of noncurrent SO<sub>2</sub> allowances as well as ongoing accounting authority to continue to implement the Major Storm Damage Reserve.

**12. Conclusion.** The testimony supporting the Settlement Agreement addresses why the Settlement Agreement is reasonable and in the public interest. Based upon our review of the record, particularly the Settlement Agreement terms and supporting testimony and exhibits, the Commission finds the Settlement Agreement is within the range of potential outcomes and represents a just and reasonable resolution of the issues.

Consistent with the foregoing findings and the Commission’s conclusion with respect to the Settlement Agreement, the Commission finds the test year end net original cost rate base (Indiana jurisdictional) for I&M is \$5,125,560,428 and is calculated as follows:

Net Plant In-Service	\$ 4,846,054,499
Fuel Stock	\$ 29,521,506
Other Materials & Supplies	\$ 124,206,512
Allowance Inventory	\$ 17,674,176
Prepaid Pension Expense	\$ 58,104,811
Regulatory Assets	\$ 49,998,924
	\$ 5,125,560,428

Settlement Agreement Attachment 1, ln. 1; Petitioner’s Ex. 15 at p. 27, Figure AJW-3.

As discussed above, the Settlement Agreement provides that for purposes of calculating the Phase-In Rate Adjustment for Phase I rates, the debt/equity ratio for investor-supplied capital will be 50.54%/49.46%. Settlement Agreement Section I.A.1.f. After giving effect to this Settlement Agreement term, the Commission finds I&M’s Phase I ratemaking capital structure (after tax) and weighted cost of capital are as follows:

**Phase I Capital Structure and Weighted Cost of Capital**

<u>Description</u>	<u>Total Company Capitalization</u> \$	<u>Percent of Total</u>	<u>Cost Rate</u>	<u>Weighted Average Cost of Capital</u>
Long-Term Debt	2,822,302,210	41.42%	4.44%	1.84%
Common Equity	2,762,126,699	40.54%	9.70%	3.93%
Customer Deposits	41,698,455	0.61%	2.00%	0.01%

<sup>58</sup> Petitioner’s Ex. 2 at pp. 25-27, 34-36; Petitioner’s Ex. 3 at pp. 9-11; Petitioner’s Ex. 13 at pp. 5-8.

<sup>59</sup> Petitioner’s Ex. 2 at p. 35; *see also* Public’s Ex. 7 at p. 3 and Petitioner’s Ex. 4 at pp. 24-26.

Acc. Def. FIT	1,170,202,985	17.17%	0.00%	0.00%
Acc. Def. JDITC	<u>17,469,705</u>	<u>0.26%</u>	7.04%	<u>0.02%</u>
Total	<u>6,813,800,053</u>	100.00%		<u>5.80%</u>

Pet. Ex. 15, Attachment AJW-1-S, page 1.

For purposes of the Phase II compliance filing, the Settlement Agreement provides the debt/equity ratio for investor-supplied capital will be adjusted to the December 31, 2022, actual ratio but no higher than a 50.00% equity ratio. Settlement Agreement Section I.A.1.f. After giving effect to this Settlement Agreement term, the Commission finds I&M’s Phase II ratemaking capital structure (after tax) and weighted cost of capital are as follows:

**Phase II Capital Structure and Weighted Cost of Capital<sup>60</sup>**

<u>Description</u>	<u>Total Company Capitalization</u> \$	<u>Percent of Total</u>	<u>Cost Rate</u>	<u>Weighted Average Cost of Capital</u>
Long-Term Debt	2,873,862,352	40.70%	4.44%	1.81%
Common Equity	2,873,862,352	40.70%	9.70%	3.95%
Customer Deposits	41,698,455	0.59%	2.00%	0.01%
Acc. Def. FIT	1,257,846,893	17.81%	0.00%	0.00%
Acc. Def. JDITC	<u>13,678,705</u>	<u>0.19%</u>	7.07%	<u>0.01%</u>
Total	<u>7,060,948,756</u>	100.00%		<u>5.78%</u>

Petitioner’s Ex. 15 at p. 15, Figure AJW-1; Attachment AJW-1-S, page 2.

Based on the evidence presented, the Commission finds Petitioner should be authorized to adjust its base rates and charges to reduce its annual operating revenue by \$94,704,680 (Settlement Attachment 1, line 16), resulting in Phase II total annual operating revenues of \$1,510,837,325 (Pet. Ex. 15, Attachment AJW-3-S, p. 6). This revenue is reasonably estimated to afford I&M the opportunity to earn net operating income of \$296,733,906 as shown in Figure AJW-2 of Mr. Williamson’s settlement testimony.

The Commission approves the phase-in of I&M’s rates as proposed by I&M and modified by the Settlement Agreement. More specifically, when I&M’s new base rates are first effective, they will include I&M’s Phase-in Rate Adjustment as set forth in Section I.A.2.b. of the Settlement Agreement (the “Phase I” rates). The PRA Rockport Unit 2 Charge will expire on December 8, 2022, on a service-rendered basis and will not be subject to true-up or further reconciliation. In the

<sup>60</sup> This table reflects a 50.00% equity ratio. I&M’s compliance filing shall use the December 31, 2022, actual ratio, but no higher than a 50.00% equity ratio. Settling Parties’ Joint Ex. 1 (Settlement Agreement) at Section I.A.1.f.

event I&M determines the PRA Rockport Unit 2 Charge has resulted in full recovery of the Rockport Unit 2 costs before December 8, 2022, I&M shall cease collection of the PRA Rockport Unit 2 Charge. As part of Phase I, I&M shall also implement a temporary PRA Excluded Capacity Credit to credit customers for excluded capacity costs consistent with the 45235 Order. The credit shall be eliminated from the PRA on a service-rendered basis effective December 8, 2022.

The Commission further finds that I&M shall certify to the Commission its net plant as of December 31, 2022, and thereafter calculate the resulting Phase II rates consistent with the Settlement Agreement. For purposes of the Phase II certification, I&M shall use the forecasted test year end net plant shown on Attachment AJW-5-S, line 8. The Phase II rates shall go into effect on the date I&M certifies its test year end net plant, or January 1, 2023, whichever is later. The net plant for Phase II rates shall not exceed the lesser of (a) I&M's forecasted test year end net plant as modified by the Settlement Agreement or (b) I&M's certified test year end net plant. I&M shall serve all Settling Parties with its certification. The OUCC and intervenors shall have 60 days from the date of certification to state objections to I&M's certified test year end net plant. If there are objections, a hearing shall be held to determine I&M's actual test year end net plant, and rates will be trued-up (with carrying charges) retroactive to January 1, 2023, notwithstanding when Phase II rates go into effect.

In addition, the Commission finds and concludes the Settlement Agreement is reasonable, supported by substantial evidence, and in the public interest. Accordingly, the Settlement Agreement is approved.

**13. Muncie Settlement Agreement.** The concerns Muncie raised are specific to that City. Petitioner's Ex. 15 at p. 2. The Muncie Settlement Agreement has no rate impact or impact on the Settlement Agreement. Petitioner's Ex. 15 at p. 2; *see also* Petitioner's Ex. 45 and Muncie Ex. 3 (Responses to December 9, 2021, Docket Entry). As noted above, however, under the Commission's Rules, all settlements must be supported by probative evidence. 170 IAC 1-1.1-17(d). In this instance Muncie prefiled no settlement testimony explaining or supporting the Muncie Settlement Agreement, and Mr. Williamson simply advised that this agreement memorializes I&M's commitment to continue to work with Muncie on the City's prospective solar generating facility in detail to assuage Muncie's concerns and clarify I&M's role. Petitioner's Ex. 15 at p. 42. No party explained the need for the Muncie Settlement Agreement, given Mr. Lucas' rebuttal testimony, or why this agreement is reasonable or in the public interest, prompting the Presiding Officers to issue a Docket Entry on December 9, 2021, eliciting evidentiary support from Muncie and I&M. The responsibility for providing adequate evidentiary support for settlements, however, rests with the parties seeking approval.

[N]o settlement agreement presented to this Commission can or does speak for itself; as noted above, settlement agreements must be supported by probative evidence to gain Commission approval. We addressed a similar issue in our Order on Less than All of the Issues in *Indiana Michigan Power Company*, Cause No. 44033 (IURC, February 22, 2012). In that Order, we reminded the parties 'that their success in obtaining approval of any Settlement Agreement ... is dependent upon the provision of adequate evidence and support for the agreement.' *Id.* at 6. In similar fashion in this proceeding, the Presiding Officers had to issue a Docket

Entry to prompt the Parties to submit sufficient evidence to support the Settlement Agreement. The Commission is concerned about the repeated need to remind the Parties of their responsibilities concerning evidentiary support for settlement agreements.

*Indiana Michigan Power Company*, Cause Nos.43992 S1 and 43992 ECCR 1 (May 23, 2012) at p. 25.

In Muncie's Docket Entry responses filed with the Commission on December 13, 2021, Muncie acknowledges the Muncie Settlement Agreement relates solely to unique matters that are important to Muncie, i.e., Muncie's prospective development of a solar photovoltaic project, and these have no rate impact. Accordingly, the other noncompany Settling Parties did not join in or take a position upon the Muncie Settlement Agreement. Per its Docket Entry responses, Muncie "leave[s] it to the Commission to decide whether it is necessary and appropriate to specifically approve the Muncie Settlement Agreement or, alternatively, accept it as the resolution" between its signatories of particular concerns Muncie raised. Muncie Ex. 3 at p. 3.

Both Muncie and I&M state in their respective Docket Entry responses that the Commission could accept the agreed resolution and find this separate agreement reasonably resolves a disputed issue or find there is no remaining contested issue the Commission needs to address. Muncie Ex. 3 at p. 3; Petitioner's Ex. 45 at p. 7. The Commission opts to take the latter alternative since the Muncie Settlement Agreement resolves matters unique to a prospective solar facility that fall outside the rate related issues this case presents; consequently, as opposed to expressly approving the separate Muncie Settlement Agreement, the Commission finds that in light of this agreement, there is no contested issue before the Commission to be addressed with respect to the concerns Muncie raised about I&M working with the City on a prospective solar project.

**14. Effect of Settlement Agreement.** Consistent with the terms of the Settlement Agreement, the Settlement Agreement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the Settlement Agreement or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at 7-8 (IURC March 19, 1997).

**15. Confidentiality.** Petitioner filed motions for protection and nondisclosure confidential and proprietary information on July 1 and October 22, 2021, both of which were supported by affidavits showing the documents to be submitted contain trade secrets within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and 24-2-3-2. Motions for confidential treatment were also filed by the Industrial Group on October 12 and October 14, 2021, to protect portions of Mr. Gorman's prefiled testimony, attachments, and workpapers. On October 25, 2021, the Industrial Group partially withdrew its October 12, 2021, motion for confidential treatment, explaining that I&M had subsequently determined portions of Mr. Gorman's testimony and attachments previously marked as confidential could be made public; thus, the Industrial Group no longer sought confidential treatment of that information. Docket Entries were issued on July 19

and November 1, 2021, finding the information that was the subject of I&M's and the Industrial Group's motions to be preliminarily confidential, after which the information was submitted to the Commission under seal. The Commission finds all such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2 and is exempt from public access and disclosure by the Commission.

**IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:**

1. The Settlement Agreement, a copy of which is attached to this Order, is approved in its entirety.

2. I&M is authorized to adjust and reduce its rates and charges for electric utility service to produce a decrease in total operating revenues of approximately 5.90% in accordance with the findings above, which rates and charges shall be designed to produce forecasted Phase II total annual operating revenues of \$1,510,837,325, that are expected to produce annual net operating income of \$296,733,906.

3. I&M is authorized to place into effect Phase I rates and charges in accordance with the findings above for retail electric service. Such rates shall be effective on and after the date of this Order, subject to the Energy Division's review and agreement with the amounts reflected.

4. I&M shall file new schedules of rates and charges along with its revised tariff under this Cause consistent with the Settlement Agreement and the rates and charges approved above.

5. I&M shall certify its net plant as of December 31, 2022, and calculate the resulting Phase II rates and charges, which shall be made effective in accordance with the findings above, subject to being contested and trued-up consistent with Finding No. 12.

6. I&M is authorized to file updated factors for its rate adjustment mechanisms in accordance with this Order, and such changes shall be effective simultaneously with approval of I&M's new basic rates.

7. I&M is authorized to implement the Tax Rider in accordance with the Settlement Agreement.

8. I&M is granted a waiver of 170 IAC 4-1-16(f) as to the disconnection process, subject to providing notification of Petitioner's ability to remotely disconnect and/or reconnect service consistent with the Settlement Agreement and Finding No. 10.C. above.

9. I&M is granted accounting authority to implement the Settlement Agreement.

10. I&M is authorized to place into effect for accrual accounting purposes revised depreciation accrual rates as provided in the Settlement Agreement.

11. I&M shall timely file in this docket all information required by the Settlement Agreement and shall make the compliance filing containing the timeline for its PLR filing per Finding No. 9.A.1.d. above.

12. The time period for the OUCC's review of I&M's FAC filings is prospectively extended to 35 days consistent with Finding No. 10.A. above, commencing with Cause No. 38702 FAC 89.

13. I&M shall add SAIFI and CAIDI statistics for tree-related outages to the vegetation management performance metrics report filed in Cause No. 44967 consistent with Finding No. 10.B. above.

14. The information filed in this Cause pursuant to I&M's and the Industrial Group's motions for protection and nondisclosure of confidential and proprietary information and preliminarily deemed confidential, as set forth in Finding No. 14 above, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

15. This Order shall be effective on and after the date of its approval.

**HUSTON, FREEMAN, KREVDA, AND OBER CONCUR; ZIEGNER ABSENT:**

**APPROVED: FEB 23 2022**

**I hereby certify that the above is a true  
and correct copy of the Order as approved.**

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**Dana Kosco**  
**Secretary of the Commission**

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER )  
COMPANY, AN INDIANA CORPORATION, )  
FOR AUTHORITY TO INCREASE ITS RATES )  
AND CHARGES FOR ELECTRIC UTILITY )  
SERVICE THROUGH A PHASE IN RATE )  
ADJUSTMENT; AND FOR APPROVAL OF )  
RELATED RELIEF INCLUDING: (1) REVISED )  
DEPRECIATION RATES; (2) ACCOUNTING ) CAUSE NO. 45576  
RELIEF; (3) INCLUSION OF CAPITAL )  
INVESTMENT; (4) RATE ADJUSTMENT )  
MECHANISM PROPOSALS; (5) CUSTOMER )  
PROGRAMS; (6) WAIVER OR DECLINATION )  
OF JURISDICTION WITH RESPECT TO )  
CERTAIN RULES; AND (7) NEW SCHEDULES )  
OF RATES, RULES AND REGULATIONS. )

STIPULATION AND SETTLEMENT AGREEMENT

Indiana Michigan Power Company (“I&M”), the Indiana Office of Utility Consumer Counselor (“OUCC”), I&M Industrial Group, Citizens Action Coalition of Indiana, Inc. (“CAC”), the City of Auburn Electric Department, the City of Muncie, Indiana, Joint Municipals (collectively the City of Ft. Wayne, the City of Marion, Marion Municipal Utilities, and the City of South Bend), the Kroger Company, Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance (“Wabash Valley”), and Walmart Inc. (collectively the “Settling Parties” and individually “Settling Party”), solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the terms and conditions set forth below represent a fair, just and reasonable resolution of the matters set forth below, subject to their incorporation by the Indiana Utility Regulatory Commission (“IURC” or “Commission”) into a final, non-appealable order (“Final Order”)<sup>1</sup> without modification or further condition that may be unacceptable to any Settling Party. If the Commission does not approve this Stipulation and Settlement Agreement (“Settlement Agreement”), in its entirety, the

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<sup>1</sup>“Final Order” as used herein means an order issued by the Commission as to which no person has filed a Notice of Appeal within the thirty-day period after the date of the Commission order.

entire Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Settling Parties.

## **I. TERMS AND CONDITIONS.**

### **A. Revenue Requirement<sup>2</sup>**

#### **1. Return on Equity, Capital Structure and Rate of Return:**

- a. The Settling Parties agree to a Commission authorized return on equity (“ROE”) of 9.70%.
- b. For purposes of setting base rates in this proceeding, I&M will retain the approximately \$159 million in cost free capital that is proposed to be removed per I&M’s proposed Net Operating Loss Carryforward (“NOLC”) adjustment pending receipt of a Private Letter Ruling (“PLR”) from the Internal Revenue Service (“IRS”), made in accordance with Section I.A.1.c below, that determines whether or not I&M’s proposed NOLC adjustment must be made in order to avoid a tax normalization violation.
  - i. Pending receipt of an IRS PLR, the Settling Parties agree that the Commission should authorize I&M to establish a regulatory asset for the return that would be associated with the inclusion of the proposed NOLC adjustment in the calculation of accumulated deferred federal income taxes (“ADFIT”) in I&M’s capital structure. The regulatory asset would also be established for the amount of any differences in I&M’s requested levels of protected and unprotected excess ADFIT (“EADFIT”) amortization (see I.A.1.d and I.A.1.e) and the settled levels of amortization. The accrual of this regulatory asset will have an effective date equal to the effective date of the rates being implemented in this proceeding.
  - ii. If the IRS PLR determines that failure to reinstate the proposed NOLC ADFIT in the calculation of I&M’s capital structure constitutes a normalization violation, I&M will initiate a limited proceeding to update I&M’s Tax Rider to reflect the NOLC adjustments, along with any Commission-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. The Settling Parties reserve rights to take any position in the limited proceeding related to the NOLC and the Company’s proposed ratemaking related thereto. All parties reserve all rights to take any position regarding the Company’s continued participation in the Tax

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<sup>2</sup> Settlement Attachment 1 updates I&M Exhibit A-1 to reflect the Settlement Agreement.

Sharing Agreement on a going forward basis in the Company's next general rate case.

- iii. If the IRS PLR determines there is no normalization violation created by the failure to reinstate the NOLC ADFIT, the regulatory asset will be written-off and will not be recovered from customers.

c. The Settling Parties agree that the Company will seek a PLR from the IRS as follows:

- i. The Settling Parties agree that the IRS rules regarding PLR requests contained in Revenue Procedure 2021-01, Appendix G, provide regulatory commissions and other interested parties certain participation rights in the PLR process. By agreeing to the terms of this Settlement the Settling Parties do not intend to limit the rights of the IURC, other interested parties or other noncompany Settling Parties from participating, to the extent allowed under the IRS rules.
- ii. The Settling Parties recognize that the American Electric Power Company ("AEP") affiliates have already submitted or are concurrently submitting PLR requests for affiliated entities on this issue. In the event that one or more AEP affiliates receive a PLR from the IRS prior to I&M, within ten (10) business days, I&M will notify the Settling Parties and provide a copy of the affiliate PLR to the Settling Parties pursuant to a non-disclosure agreement. I&M will provide a confidential draft of the I&M PLR to the noncompany Settling Parties and will confer on a neutral description of the facts and Settling Parties' positions in the PLR request to objectively frame the issue while adhering to IRS guidelines and requirements (Rev. Proc. 2021-01) before the PLR request is submitted to the IRS for resolution. The noncompany Settling Parties shall provide feedback to I&M on the draft PLR no later than five (5) business days after receiving the PLR draft. I&M will convene a virtual meeting to discuss the feedback on the sixth business day following transmittal to the other Settling Parties. As the signatory to the PLR, I&M shall make the final determination of the contents of the PLR and will also make good faith efforts to incorporate timely, reasonable feedback from the noncompany Settling Parties. The Settling Parties retain their rights to communicate with the IRS regarding the PLR as set forth in IRS Internal Revenue Bulletin No. 2021-1, page 103.
- iii. If the IRS requests additional information related to the PLR request, the Company shall provide the noncompany Settling Parties with timely, meaningful notice of the IRS request for additional information before a response is due, and provide a copy of the Company's response once it has been made.

- iv. The Company will file notice of the results of the ruling with the Commission and notify the Settling Parties within ten (10) business days of receipt of the PLR.
  - v. No Settling Party shall be deemed to have waived any position in a subsequent case as to whether I&M may recover the costs it incurs associated with the PLR Request.
  - vi. For purposes of permitting the Commission to make the necessary findings consistent with the terms of this stipulation, I&M will waive confidential treatment of: (1) the fact of its request for a PLR; and (2) the overall results of the PLR.
- d. The Settling Parties agree that the Tax Rider, as approved in this case, will serve only two purposes: (1) to credit customer rates for the remaining benefits associated with unprotected EADFIT as defined in this Settlement Agreement and (2) to implement ratemaking adjustments associated with an IRS PLR that requires I&M to make its proposed NOLC adjustment. For purposes of setting rates in this proceeding for the Tax Rider, I&M agrees not to adjust the remaining balance of unprotected EADFIT for any NOLC impact. I&M agrees to a \$14,623,272 (Indiana Jurisdictional) EADFIT credit as proposed by Joint Municipal witness Cannady and a seven (7) month amortization period. The total monthly EADFIT amortization to be credited to customers will be grossed up for taxes at a rate of 1.3580 and will include a carrying charge on the unamortized balance based on the pre-tax Weighted Average Cost of Capital (“WACC”) approved in this proceeding. The Settling Parties agree that I&M will reconcile the Tax Rider to reflect its actual unprotected EADFIT amortization and the monthly remaining balance.
- e. The base rate revenue requirement will be reduced by \$5,914,719 (Total Company), \$3,327,861 (Indiana Jurisdictional), to reflect the protected EADFIT impact to deferred tax expense for the NOLC.
- f. For purposes of calculating the Phase-In Rate Adjustment for Phase I rates, the Debt/Equity ratio will be 50.54%/49.46% through close of Test Year. For purposes of the Phase II compliance filing, the Debt/Equity ratio will be adjusted to the December 31, 2022, actual ratio based on shareholder contributions of debt and equity, but will be no higher than a 50.00% equity ratio.
- g. The authorized base rate net operating income will be \$296,733,905.
2. **Rockport Unit 2 Costs.** Consistent with the Cause No. 45546 Settlement Agreement, the Parties agree to removal of lease costs and all other costs and expenses associated with Rockport Unit 2 from rates:
- a. **Phase I Base Rates.** I&M agrees to remove from I&M’s proposed base rates the revenue requirement of approximately \$141 million of Rockport Unit 2 costs, as identified in Settlement Attachment 2, at the time new base rates are implemented (Phase I).

- b. **Phase-In Rate Adjustment (“PRA”).** Upon implementation of new Phase I base rates, I&M will simultaneously implement a temporary charge to be collected through its PRA, by which I&M will continue to recover the costs and expenses associated with Rockport Unit 2 that are not currently tracked in other riders (the “PRA Rockport Charge”). The PRA Rockport Charge will expire on December 8, 2022 on a service-rendered basis and will not be subject to true-up or further reconciliation. In the event I&M determines that the PRA Rockport Charge has resulted in full recovery of the Rockport Unit 2 costs identified by type and amount below before December 8, 2022, it agrees to cease collection of the PRA Rockport Charge. The PRA Rockport Charge will include the following:
- i. A return on a fixed \$15,143,223 (Indiana Jurisdictional) level of fuel and consumables inventory through December 7, 2022, at I&M’s Phase I WACC grossed up for taxes.
  - ii. I&M will recover the prorated share of a fixed \$1,035,878 (Indiana Jurisdictional) annual level of fuel handling and disposal expenses through 12/7/2022.
  - iii. I&M will recover its Rockport Unit 2 lease expense incurred through the end of calendar year 2022, based on the prorated share of I&M’s annual \$48,924,630 (Indiana Jurisdictional) lease expense. Since the PRA Rockport Charge will end on December 8, 2022, for purposes of setting the PRA Rockport Charge, I&M’s Rockport Unit 2 Lease expense will be grossed up to recognize the full annual lease expense for calendar year 2022.
  - iv. I&M will recover the prorated share of a fixed \$13,240,324 (Indiana Jurisdictional) annual level of other operations and maintenance (“O&M”) expense (\$12,177,941) and property tax expense (\$1,062,383) through December 7, 2022.
  - v. The revenue requirement for the PRA Rockport Charge will be allocated, and retail rates designed, consistent with the agreed allocation methodology for demand and energy costs used in I&M riders to arrive at the agreed rider revenue allocation shown in Settlement Attachment 3.
- c. **Environmental Cost Rider (“ECR”) and Resource Adequacy Rider (“RAR”).** Upon implementation of new Phase I base rates, I&M will simultaneously implement new ECR and RAR rates to continue recovering the Rockport Unit 2 costs and expenses currently recovered through those riders through the term of the Rockport Unit 2 lease. I&M will make a filing in 2022 to revise its ECR and RAR rates effective with the first billing cycle in January 2023 to exclude the Rockport Unit 2 ECR and RAR costs that are no longer recoverable after the end of the lease. The timing of the 2023 ECR and RAR rate changes will be dependent upon a Commission order allowing new rider rates to be implemented.



**5. PJM NITS Costs:**

- a. I&M will provide the same annual presentation to Settling Parties on a going-forward basis that it currently provides to the Michigan Public Service Commission in order to provide additional detail regarding supplemental projects consistent with the information provided through the PJM stakeholder process.
- b. An annual cap will be placed on the PJM NITS costs reflected in FERC accounts 4561035 and 5650016 recovered through the PJM rider at I&M's Indiana Jurisdictional amount forecasted for 2024 plus 15%, which totals \$381.3 million (Indiana Jurisdictional). Annual NITS costs in any year that exceed \$381.3 million, together with the associated NITS rider revenue requirement and carrying costs, will be placed in a regulatory asset for recovery in I&M's next base rate case. The Settling Parties reserve their rights to take any position with respect to the appropriate amortization period and related going-forward return on any unamortized balance of any regulatory asset created pursuant to this term of this Settlement Agreement.

**6. AMI:**

- a. The Parties agree to include I&M's capital forecast period (2021-2022) AMI capital (\$54.649 million) and O&M costs (\$4.77 million) in base rates set in this Cause.
- b. I&M agrees to withdraw its request for an AMI rider.
- c. I&M is not prevented from seeking recovery of additional AMI investment and operating and maintenance costs in its next base rate case(s).
- d. Settling Parties agree not to challenge the reasonableness of I&M's decision to transition from AMR meters to AMI meters or the reasonableness of I&M's plan to deploy AMI meters over a four-year period, as presented in this Cause, in any future proceeding.

**7. OPEB/Pre-Paid Pension Assets:**

- a. The Parties agree that rate base shall include the pre-paid pension asset in the amount of \$80.7 million (Total Company), \$58.1 million (Indiana Jurisdictional).
- b. The Parties agree to the removal of the \$96,252,892 (Total Company), \$69,324,472 (Indiana Jurisdictional), OPEB prepayment asset from rate base.

**8. Non-Rockport Unit 2 Miscellaneous Rate Base Adjustments:**

For the purpose of calculating revenue requirements in this case, I&M will reduce its proposed rate base by \$26.4 million as follows. Nothing in this agreement precludes I&M from seeking to include the removed items in its cost of service in a future case.

- a. Remove \$3,783,088 EV Fast Charging costs;
- b. Remove \$568,770 Flex Pay Program costs;
- c. Remove \$2,023,141 unamortized COVID-19 deferred bad debt expense; and
- d. Remove \$20 million of forecasted Distribution plant investment.

## **9. Expense Adjustments:**

For the purpose of calculating revenue requirements in this case, I&M will reduce its proposed O&M expenses as follows. Nothing in this agreement precludes I&M from seeking recovery of these type of expenses in a future case.

- a. \$10 million decrease in depreciation expense;
- b. \$2.0 million decrease in nuclear decommissioning expense. The Settling Parties agree that I&M may seek an adjustment to the funding level of the Nuclear Decommissioning Trust based on future analysis of the adequacy of the Nuclear Decommissioning Trust funds to pay for decommissioning;
- c. \$293,773 deferred COVID-19 bad debt expense; and
- d. \$4.0 million decrease in other O&M expense from I&M's Test Year forecast.

## **10. Other Provisions:**

- a. I&M agrees to provide the OUCC with a 35-day review period in its FAC proceeding, starting with Cause No. 38702 FAC-89, which is expected to be filed by I&M late July 2022 or early August 2022.
- b. I&M agrees to include vegetation management reliability statistics in its Cause No. 44967 performance metrics report.
- c. I&M agrees to notify its customers of its ability to remotely disconnect/reconnect via bill insert, text, and email. This notice shall identify a customer's rights prior to disconnection, including a description of the process I&M will use when attempting to contact its customers before a remote disconnection, information on how to contact I&M's customer service department and Low Income Home Energy Assistance Program ("LIHEAP"), and information on how to add an email address and/or mobile phone number to receive notifications from the utility.
- d. I&M agrees to withdraw its request to change the name of the Solar Power Rider, and to not make related tariff language modifications, without prejudice to seek such a name change and related tariff language modifications in a future proceeding.
- e. I&M agrees to withdraw its request to implement the Flex Pay Program without prejudice to seek approval for such a program in a future proceeding. Should I&M pursue a prepaid program such as this in the future, I&M agrees that its proposal will reflect that it will (i) not market to customers facing disconnection for non-payment or customers concerned about the deposit amount required by I&M; (ii) market the program as a voluntary service; and (iii) ensure customers can purchase service credits 24 hours per day, seven-days per week via phone or internet with no transaction fees. I&M agrees to meet with interested stakeholders, including CAC, prior to filing the program to receive input on the development of the program, including concerns related to the winter disconnection moratorium as defined in Ind. Code Section 8-1-2-121.

- f. I&M agrees to withdraw its request to implement the Electric Vehicle ("EV") Fast Charging program without prejudice to seek approval for such a program in a future proceeding.
- g. Without ratepayer contribution, I&M agrees to fund \$175,000 per year in 2022 and 2023 to continue the Low Income Arrearage Forgiveness program currently in place as a result of the settlement agreement in Cause No. 44967.
- h. I&M agrees to limit the customer deposit to no more than \$50 for customers identified as LIHEAP participants or LIHEAP-eligible.
- i. I&M will provide a \$150,000 contribution to the community action program network of Indiana Community Action Association to facilitate low-income weatherization in I&M's service territory, including but not limited to using funds to address health and safety issues preventing weatherization, and to assist in bill payment and deposit assistance for I&M LIHEAP eligible households. I&M's revenue deficiency in this Cause will not be adjusted to include the incremental costs of this contribution.
- j. I&M will provide a \$100,000 contribution to the Indiana Utility Ratepayer Trust. I&M's revenue deficiency in this Cause will not be adjusted to include the incremental costs of this contribution.

**B. Cost of Service and Rate Design**

1. Settling Parties agree that I&M's fixed monthly Rate RS charge will remain at \$15 per month. The Settling Parties agree the fixed monthly charge for Rate RS-TOD and Rate RS-TOD2 will increase to \$17 per month.
2. The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among I&M's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that Settlement Attachment 3 specifies the revenue allocation agreed to by all Settling Parties. This revenue allocation is determined strictly for settlement purposes and is without reference to any particular, specific cost allocation methodology.
3. The Settling Parties agree to a Tariff I.P. rate design that produces the agreed upon energy and demand charges for each sub-class as set out in Settlement Attachment 3. As further described in the I&M and Industrial Group testimony in support of the Settlement Agreement, Rate IP demand charges by sub-class were increased to reflect the approximate average power factor by sub-class and any remaining demand related costs were then left in the first block energy charge.
4. I&M agrees not to combine Tariff G.S. and Tariff L.G.S. base rates and instead will (a) implement an excess kVa charge in tariff L.G.S. and (b) unify aspects of Tariff G.S. and Tariff L.G.S. rider rates. A copy of the revised tariff language will be included with I&M's testimony in support of the Settlement Agreement.
5. The Settling Parties agree that I&M may adopt its proposed new provision number 27 in its Terms and Conditions as modified below:

27. Customer Requested Disconnection / Reconnection at Station Transformer. Whenever, at the customer's request, the Company is required to perform a disconnection and / or reconnection at a customer or Company owned station transformer, switch or breaker, the customer shall reimburse the Company for the entire cost incurred in making such connections which shall include all labor costs, transportation and equipment costs and any materials used not to exceed \$1,500. In the event that such costs are expected to exceed \$1,500, the Company shall provide the Customer with a binding estimate detailing the scope of work and associated costs to perform such work prior to the date on which the work is schedule to commence.

6. I&M agrees to retain language it had proposed to strike from Tariffs G.S., L.G.S., I.P. and W.S.S. stating that each tariff remains available to customers having other sources of energy supply who purchase standby or backup electric service from the Company, the applicable maximum and minimum demands for which such customers must contract, the Company's service obligation, and references to the applicable minimum charge. As proposed in its case in chief, I&M agrees to strike from each of these tariffs the sentence which reads: "*Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods.*" A copy of the revised tariff language will be included with I&M's testimony in support of the Settlement Agreement.
7. With respect to the Company's Tariff R.S. – CPP, I&M agrees to propose in its next base rate case provisions addressing the exclusion of holidays from the days for which Critical Peak Events may be called. The Settling Parties further agree that I&M is not receiving authorization for Tariff R.S. – CPP as an "opt-out" rate in this proceeding, and that I&M must obtain Commission approval for any opt-out rate provisions prior to implementation.

### **C. Remaining Issues**

1. Any matters not addressed by this Settlement Agreement will be adopted as proposed by I&M in its direct case.
2. The Settling Parties agree to seek Commission approval, as described in Part II below, so that the Commission can issue a final order consistent with IC 8-1-2-42.7(f).

## **II. PRESENTATION OF THE SETTLEMENT AGREEMENT TO THE COMMISSION.**

A. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement.

B. I&M will, and each of the other Settling Parties may, file testimony specifically supporting the Settlement Agreement. The Settling Parties agree to provide each other with an opportunity to review drafts of testimony supporting the Settlement Agreement and to consider the input of the other Settling Parties. Such evidence, together with the evidence previously

prefiled in this Cause will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement Agreement and evidence conditionally, and that, if the Commission fails to approve this Settlement Agreement in its entirety without any change or approves it with condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn and the Commission will continue to hear this with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

C. A Commission Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on all Settling Parties as an Order of the Commission.

### **III. EFFECT AND USE OF SETTLEMENT AGREEMENT.**

A. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except to the extent necessary to implement and enforce its terms. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

B. Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

C. This Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement.

D. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of

any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

E. The evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Settling Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible after the filing of this Settlement Agreement and the final evidentiary hearing.

F. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

G. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

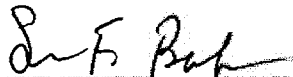
H. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of the Commission Order approving this Settlement Agreement in its entirety and without change or condition(s) acceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement).

I. The provisions of this Settlement Agreement shall be enforceable by any Settling Party first before the Commission and thereafter in any state court of competent jurisdiction as necessary.

J. This Settlement Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

**ACCEPTED and AGREED as of the 16th day of November, 2021.**

INDIANA MICHIGAN POWER COMPANY

A handwritten signature in black ink, appearing to read "S. F. Baker", written over a horizontal line.

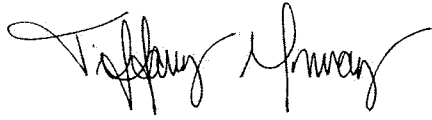
Steven F. Baker

I&M President and Chief Operating Officer

Indiana Michigan Power Center

Fort Wayne, Indiana 46802

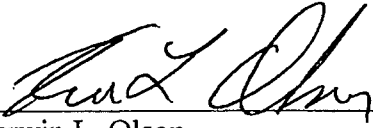
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR



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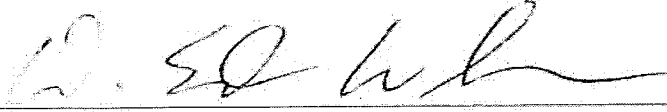
Randall Helmen, Chief Deputy Consumer Counselor  
Tiffany Murray, Deputy Consumer Counselor  
Office of Utility Consumer Counselor  
115 West Washington Street, #1500S  
Indianapolis, Indiana 46204

CITIZENS ACTION COALITION OF  
INDIANA, INC.

A handwritten signature in black ink, appearing to read "Kerwin L. Olson", written over a horizontal line.

Kerwin L. Olson  
Citizens Action Coalition  
1915 West 18th Street, Suite C  
Indianapolis, Indiana 46202

THE CITY OF AUBURN ELECTRIC DEPARTMENT

A handwritten signature in black ink, appearing to read "W. Erik Weber", written over a horizontal line.

W. Erik Weber, Esquire  
Mefford Weber and Blythe  
130 East Seventh Street  
Auburn, IN 46706-1839

Mark W. Cooper  
Attorney at Law  
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THE CITY OF FORT WAYNE, INDIANA



---

Brian C. Bosma

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CITY OF MARION, INDIANA, and MARION MUNICIPAL UTILITIES  
AND THE CITY OF SOUTH BEND, INDIANA



---

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Nikki G. Shultz


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THE CITY OF MUNCIE, INDIANA



---

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THE KROGER COMPANY



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Kurt J. Boehm, Esq.

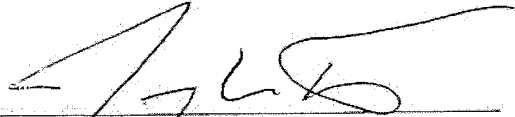
Jody Kyler Cohn, Esq.

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Cincinnati, Ohio 45202

WABASH VALLEY POWER ASSOCIATION, INC.  
D/B/A WABASH VALLEY POWER ALLIANCE



Jeremy L. Fetty

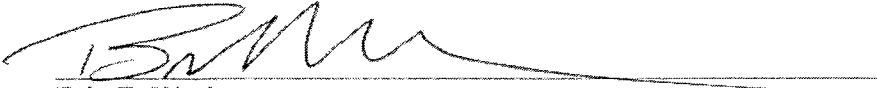
Liane K. Steffes

PARR RICHEY

251 N. Illinois Street, Suite 1800

Indianapolis, IN 46204

WALMART INC.

A handwritten signature in black ink, appearing to read 'E. Kinder', is written over a horizontal line.

Eric E. Kinder  
SPILMAN THOMAS & BATTLE, PLLC  
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Charleston, WV 25321

Barry A. Naum  
SPILMAN THOMAS & BATTLE, PLLC  
1100 Bent Creek Boulevard, Suite 101  
Mechanicsburg, PA 17050

DMS 21275905v1

**INDIANA MICHIGAN POWER COMPANY  
INDIANA JURISDICTIONAL PROJECTED REQUIRED RATE RELIEF SUMMARY  
FOR THE TEST YEAR ENDED DECEMBER 31, 2022**

( 1 )	( 2 )	( 3 )	( 4 )
Line No.	Description	Source	Indiana Jurisdictional Amount
1	Adjusted Original Cost Rate Base	Attachment JCD-1-S	\$ 5,125,560,428
2	Required Rate of Return	Attachment AJW-1-S	5.78%
3	Income Requirement	Line 1 x Line 2	<u>\$ 296,288,136</u>
4	Less: Net Electric Operating Income	Attachment JCD-1-S	\$ 357,455,166
5	Income Deficiency	Line 3 - Line 4	\$ (61,167,030)
6	Gross Revenue Conversion Factor	Attachment AJW-6-S	<u>1.3580</u>
7	Jurisdictional Revenue Deficiency	Line 5 x Line 6	\$ (83,064,827)
8	Remove Transmission Owner Costs, Revenues	Attachment JLF-1-S	\$ 605,355
9	Total Required Rate Relief Before Phase-In Credit	Line 7 + Line 8	<u>\$ (82,459,473)</u>
10	Less: Current Revenue for Ongoing Riders	Attachment AJW-3-S	\$ (243,618,128)
11	Plus: Proposed Rider Revenue	Attachment AJW-3-S	\$ 321,396,541
12	Total Rate Change <u>Including</u> Phase-In Credits	Line 9 + Line 10 + Line 11	<u>\$ (4,681,060)</u>
13	Forecasted Revenues Before Increase	Attachment AJW-3-S	\$ 1,605,545,069
14	Percent Increase	Line 12 / Line 13	-0.29%
15	<u>Riders that Expire or Change between December 2022 and January 2023</u>		
A	Phase-In Credit - Plant	WP-JLF-7-S	\$ (27,171,209)
B	Phase-In Credit - Excluded Capacity	WP-JLF-6-S	\$ (31,503,678)
C	Phase-In Credit - Rockport (2022 charge)	WP-JLF-6-S	\$ 70,942,602
D	Resource Adequacy Rider - Rockport	WP-JLF-6-S	\$ 77,304,123
E	ECR - Rockport (2022)	WP-JLF-6-S	\$ 1,310,171
F	Subtotal - Items Ending in 2022 (Included in Line 11)		<u>\$ 90,882,009</u>
G	Phase-In Credit - Plant (TBD Jan 2023)	N/A	\$ -
H	Phase-In Credit - Rockport NBV (2023)	WP-JLF-6-S	\$ (18,075,753)
I	ECR - SO2 (2023)	WP-JLF-6-S	\$ 3,028,225
J	ECR - Rockport NBV (2023)	WP-JLF-6-S	<u>\$ 15,905,917</u>
K	Subtotal - Items Beginning in 2023		<u>\$ 858,389</u>
16	Total Rate Change - December 31, 2022	Line 12 - 15F + 15K	<u>\$ (94,704,680)</u>
17	Percent Increase	Line 16 / Line 13	-5.90%

Rockport Unit 2 Post Lease Cost Adjustment Calculation

Component	Total Company Amount	IN Allocator <sup>1/</sup>	IN Jurisdictional	Adj Mechanism
<b>Test Year Rate Base @ 12/31/22</b>				
Fuel Inventory	\$ 21,189,656	Energy Excl Shop	69.569%	\$ 14,741,381 PRA
Consumables Inventory	\$ 568,409	Demand	70.696%	\$ 401,843 PRA
	\$ 21,758,065			\$ 15,143,223
	7.20%			7.20%
	\$ 1,566,337			\$ 1,090,142 a
<b>2022 Test Year Operating Expenses</b>				
Fuel Expense	\$ 1,488,999	Energy Excl Shop	69.569%	\$ 1,035,878 PRA
Consumables Expense	\$ 1,791,885	Energy Excl Shop	69.569%	\$ 1,246,592 ECR
Allowances Expense	\$ 52,488	Energy Excl Shop	69.569%	\$ 36,515 ECR
AEG UPA - Non-Fuel	\$ 107,252,483	Demand	70.696%	\$ 75,823,215 RAR
Lease Expense	\$ 69,204,240	Demand	70.696%	\$ 48,924,630 PRA
Other O&M Expense	\$ 17,232,615	Various	70.668%	\$ 12,177,941 PRA
Property Tax Expense	\$ 1,432,072	Net Plant	74.185%	\$ 1,062,383 PRA
	\$ 198,454,782			\$ 140,307,154 b
				Total Revenue Requirement Impact = \$ 141,397,297 a+b
<b>Summary of Costs in I&amp;M's FAC Basing Point</b>				
Fuel Expense	\$ 14,264,901	Energy Excl Shop	69.569%	\$ 9,923,915
AEG UPA - Fuel	\$ 13,921,021	Energy Excl Shop	69.569%	\$ 9,684,682
	\$ 28,185,922			\$ 19,608,596

Sources:

<sup>1/</sup> Attachment JCD-1-S (pg. 15)

Indiana Michigan Power Company  
Proposed Revenue Allocation  
Test Year Twelve Months Ending December 31, 2022  
Phase I Rate Change - 2022

Current Class (1)	Adjusted Current Revenue (2)	Continuing Rider Revenue (3)	Total Revenue (4) = (2) + (3)	Current ROR % (5)	Current ROR Index (6)	Proposed Basic Rate Increase (7) = (8) - (2)	Proposed Basic Rate Revenue (8)	Rider Revenue (9)	Total Revenue (10) = (8) + (9)	% Increase (11) = (10) / (4)	Proposed ROR % (12)	Proposed ROR Index (13)
RS	566,975,891	105,400,193	672,376,084	6.72	96	(30,128,430)	536,847,461	129,985,590	666,833,052	-0.82%	5.80	100
GS	147,504,396	27,277,501	174,781,897	8.97	129	(12,782,970)	134,721,426	40,060,472	174,781,898	0.00%	7.58	131
LGS	259,294,138	49,449,286	308,743,424	5.95	85	(13,741,225)	245,552,914	64,730,880	310,283,793	0.50%	4.83	83
IP	265,654,055	55,981,667	321,635,722	7.48	107	(22,157,698)	243,496,356	78,139,365	321,635,722	0.00%	5.78	100
MS	2,561,240	495,112	3,056,352	7.20	103	(197,269)	2,363,971	640,009	3,003,981	-1.71%	5.80	100
WSS	9,781,054	1,717,081	11,498,135	6.43	92	(887,914)	8,893,140	2,604,995	11,498,135	0.00%	4.48	77
IS	245,845	15,940	261,785	11.42	164	(37,760)	208,085	27,548	235,633	-9.99%	8.57	148
EHG	575,437	104,228	679,665	6.88	96	(40,394)	535,043	144,622	679,665	0.00%	5.40	93
OL	6,482,376	(17,838)	6,464,538	9.73	140	(583,495)	5,898,881	(80,150)	5,818,731	-9.99%	8.25	142
SL	5,127,804	17,695	5,145,499	11.35	163	(519,514)	4,608,290	23,174	4,631,464	-9.99%	9.62	166
Subtotal	1,264,202,237	240,440,865	1,504,643,102	6.97	100	(81,076,669)	1,183,125,568	316,276,505	1,499,402,073	-0.35%	5.80	100
Interruptible	97,724,704	3,177,263	100,901,967			(1,382,803)	96,341,901	5,120,036	101,461,937	0.55%		
Total Basic Rates	1,361,926,941					(82,459,472)	1,279,467,469				5.78	
Riders	243,618,128	243,618,128				77,778,413	321,396,541	321,396,541				
Total	1,605,545,069		1,605,545,069			(4,681,059)	1,600,864,010		1,600,864,010	-0.29%		

**Indiana Michigan Power Company**  
**Proposed Revenue Allocation**  
**Test Year Twelve Months Ending December 31, 2022**  
**Phase I Rate Change - 2022 and Phase II Rate Change - December 2022/January 2023**

Current Class (1)	Current			Proposed			Phase 1			Phase 2		
	Total Revenue (2)	Basic Rate Increase (3)	Basic Rate Revenue (4)	Rider Revenue (5)	Total Revenue (6) = (4) + (5)	% Increase (7) = (6) / (2)	Rider Revenue (8)	Total Revenue (9) = (4) + (8)	% Increase (10) = (9) / (6)			
RS	672,376,084	(30,128,430)	536,847,461	129,985,590	666,833,052	-0.82%	96,230,180	633,077,641	-5.06%			
GS	174,781,897	(12,782,970)	134,721,426	40,060,472	174,781,898	0.00%	29,172,981	163,894,406	-6.23%			
LGS	308,743,424	(13,741,225)	245,552,914	64,730,880	310,283,793	0.50%	45,923,954	291,476,868	-6.06%			
IP	321,635,722	(22,157,698)	243,496,356	78,139,365	321,635,722	0.00%	54,329,502	297,825,858	-7.40%			
MS	3,056,352	(197,269)	2,363,971	640,009	3,003,981	-1.71%	462,927	2,826,898	-5.89%			
WSS	11,498,135	(887,914)	8,893,140	2,604,995	11,498,135	0.00%	1,812,496	10,705,636	-6.89%			
IS	261,785	(37,760)	208,085	27,548	235,633	-9.99%	21,157	229,242	-2.71%			
EHG	679,665	(40,394)	535,043	144,622	679,665	0.00%	106,079	641,121	-5.67%			
OL	6,464,538	(583,495)	5,898,881	(80,150)	5,818,731	-9.99%	(30,219)	5,868,662	0.86%			
SL	5,145,499	(519,514)	4,608,290	23,174	4,631,464	-9.99%	(493)	4,607,797	-0.51%			
Subtotal	1,504,643,102	(81,076,669)	1,183,125,568	316,276,505	1,499,402,073	-0.35%	228,028,563	1,411,154,131	-5.89%			
Interruptible	100,901,967	(1,382,803)	96,341,901	5,120,036	101,461,937	0.55%	3,344,358	99,686,259	-1.75%			
Subtotal Basic Rates	(82,459,472)	1,279,467,469										
Riders	Incl. Above	77,778,413		321,396,541	Incl. Above		231,372,921	Incl. Above				
Total	1,605,545,069	(4,681,059)			1,600,864,010	-0.29%		1,510,840,390	-5.62%			

**Indiana Michigan Power Company  
Proposed Rider Allocation  
Test Year Twelve Months Ending December 31, 2022**

<u>Current Class</u> (1)	<u>Phase 1 Rider Revenue</u> (5)	<u>Resource Adequacy Rider (RAR)</u> (3)	<u>Environmental Cost Rider (ECR)</u> (3)	<u>Phase-In Rate Adj. Rider (PRA)</u> (3)	<u>Phase 2 Rider Revenue</u> (3)
RS	129,985,590	(31,817,545)	7,139,505	(9,077,371)	96,230,180
GS	40,060,472	(9,763,738)	2,163,186	(3,286,940)	29,172,981
LGS	64,730,880	(15,625,895)	3,598,785	(6,779,814)	45,923,954
IP	78,139,365	(18,073,492)	4,216,778	(9,953,150)	54,329,502
MS	640,009	(154,755)	34,930	(57,258)	462,927
WSS	2,604,995	(625,122)	146,750	(314,127)	1,812,496
IS	27,548	(7,319)	1,681	(753)	21,157
EHG	144,622	(35,448)	7,913	(11,009)	106,079
OL	(80,150)	(6,980)	6,750	50,161	(30,219)
SL	23,174	(10,624)	10,005	(23,047)	(493)
Subtotal	316,276,505	(76,120,917)	17,326,283	(29,453,308)	228,028,563
Interruptible	5,120,036	(1,183,205)	297,688	(890,160)	3,344,358
Total	321,396,541	(77,304,122)	17,623,971	(30,343,468)	231,372,921
Revenue Verification Diff.		630	5,132	3,681	
Net Change in Riders	321,396,541	(77,303,492)	17,629,103	(30,339,787)	231,372,921
<b><u>Items Ending in 2022</u></b>					
Rockport Unit 2 Costs Ending in 2022		(77,303,492)	(1,308,157)	(70,941,635)	
Excluded Capacity Credit Ending in 2022				31,504,295	
Test Year Plant Addition Credit Ending in 2022				27,172,019	
<b><u>Items Beginning in 2023</u></b>					
SO2 Allowance Collection			3,025,300		
Plant Credit for Rockport NBV				(18,074,466)	
Levelized Charge for Rockport NBV			15,911,960		
Net Change in Riders		(77,303,492)	17,629,103	(30,339,787)	

**Indiana Michigan Power Company**  
**Proposed IP Rates**  
**Test Year Twelve Months Ending December 31, 2022**

<u>Class</u> (1)	<u>Demand Charge (\$/kW)</u> (2)	<u>First 410 kWh per kW (¢/kWh)</u> (3)	<u>Over 410 kWh per kW (¢/kWh)</u> (4)	<u>Minimum Demand Charge (\$/kW)</u> (5)	<u>Excess kVAr Charge (\$/kVAr)</u> (6)	<u>Monthly Service Charge (\$)</u> (7)
327 Secondary	\$15.645	5.540	1.104	\$ 20.250	\$ 1.50	\$ 155.00
322 Primary	\$13.113	5.185	1.067	\$ 17.559	\$ 1.50	\$ 235.00
323 Subtransmission	\$10.034	4.940	1.053	\$ 14.541	\$ 1.50	\$ 235.00
324 Transmission	\$ 9.918	4.547	1.045	\$ 14.374	\$ 1.50	\$ 235.00

**CCC Interrogatory #033**

**Interrogatory**

**Reference:**

**Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 71**

Question(s):

a) Please provide an alternative version of Figure 20 that shows the full breakdown of the generation capacity by type. For example, Duke Energy has 9,200 MW of nuclear generation capacity and 1,300 MW of hydroelectric generation capacity. Please provide a breakdown of the other types of generation capacity that bring the total regulated generation capacity to 54,000 MW. Please also provide the data underlying this alternative version of Figure 20 in excel format.

**Response**

a) Please see Attachment 1 for the requested data.

**CCC Interrogatory #035**

**Interrogatory**

**Reference:**

**Exhibit C1, Tab 1, Schedule 2, pp. 2, 5-7**

Question(s):

- a) Please discuss the likelihood that OPG will access the U.S. bond market during the 2027-2031 period.
- b) Please provide the underlying calculations for Charts 1 & 2 showing the application of the equally weighted blend of the two Bloomberg forecasts (and the adjustment for the years where the Bloomberg Bond Yield Median forecast was not available).
- c) Please provide the credit spreads for each year of the three-year average that supports the 135-basis points credit spread for 10-year bonds and the 160-basis point credit spread for 30-year bonds.
- d) Please provide the historical data supporting the issuance costs included in forecast long-term debt rates.
- e) Please provide the current 30-year GoC bond rate at the time of filing the IR responses.
- f) Please provide the 10-year bond forecast for 2027-2031 based on the previous approach used by OPG (i.e., Global Insight bond rate forecast).
- g) Please advise whether OPG has a recent credit spread quote from the major banks (i.e., a point in time estimate received at the time it was preparing the current application). If so, please provide the credit spread(s).

**Response**

- a) Refer to Ex. L-C1-Staff-034, part (a).
- b) To show the application of the equally weighted blend of the two Bloomberg forecasts, OPG has first included the monthly 10-year and 30-year Bloomberg forward GoC rates for 2026-2031 in Chart 1 & 1A below, which were used to derive such average quarterly forward rates.

**Chart 1 – Monthly and Average Quarterly 10-Year Forward GoC Rates (%)**

Year	Q1			Q2			Q3			Q4		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.28	3.29	3.30	3.32	3.33	3.35	3.36	3.37	3.39	3.40	3.41	3.43
	<b>3.29</b>			<b>3.33</b>			<b>3.37</b>			<b>3.41</b>		
2027	3.44	3.45	3.46	3.47	3.48	3.49	3.51	3.52	3.53	3.54	3.55	3.56
	<b>3.45</b>			<b>3.48</b>			<b>3.52</b>			<b>3.55</b>		
2028	3.57	3.58	3.59	3.60	3.61	3.63	3.64	3.65	3.66	3.66	3.67	3.68
	<b>3.58</b>			<b>3.61</b>			<b>3.65</b>			<b>3.67</b>		
2029	3.69	3.69	3.70	3.71	3.72	3.73	3.73	3.74	3.75	3.76	3.76	3.77
	<b>3.69</b>			<b>3.72</b>			<b>3.74</b>			<b>3.76</b>		
2030	3.77	3.78	3.79	3.79	3.80	3.81	3.81	3.82	3.83	3.83	3.83	3.84
	<b>3.78</b>			<b>3.80</b>			<b>3.82</b>			<b>3.83</b>		
2031	3.84	3.85	3.85	3.86	3.86	3.87	3.87	3.87	3.88	3.88	3.88	3.89
	<b>3.85</b>			<b>3.86</b>			<b>3.87</b>			<b>3.88</b>		

**Chart 1A – Monthly and Average Quarterly 30-Year Forward GoC Rates (%)**

Year	Q1			Q2			Q3			Q4		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	3.73	3.73	3.74	3.74	3.75	3.75	3.76	3.76	3.76	3.77	3.77	3.78
	<b>3.73</b>			<b>3.75</b>			<b>3.76</b>			<b>3.77</b>		
2027	3.78	3.79	3.79	3.79	3.80	3.80	3.80	3.81	3.81	3.82	3.82	3.82
	<b>3.78</b>			<b>3.80</b>			<b>3.81</b>			<b>3.82</b>		
2028	3.83	3.83	3.83	3.84	3.84	3.84	3.85	3.85	3.85	3.86	3.86	3.86
	<b>3.83</b>			<b>3.84</b>			<b>3.85</b>			<b>3.86</b>		
2029	3.86	3.87	3.87	3.87	3.87	3.88	3.88	3.88	3.88	3.89	3.89	3.89
	<b>3.87</b>			<b>3.87</b>			<b>3.88</b>			<b>3.89</b>		
2030	3.89	3.89	3.90	3.90	3.90	3.90	3.90	3.91	3.91	3.91	3.91	3.91
	<b>3.89</b>			<b>3.90</b>			<b>3.91</b>			<b>3.91</b>		
2031	3.91	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.92	3.93	3.93	3.93
	<b>3.92</b>			<b>3.92</b>			<b>3.92</b>			<b>3.93</b>		

Second, in Chart 2 & 2A below, OPG has calculated the difference between the quarterly Bloomberg forward GoC rates from Chart 1 & 1A above, and the Bloomberg Bond Yield Median Forecast (“BYFC”) for 2026 and 2027. The average difference across the eight quarters was -0.17% for the 10-year GoC bond rates and -0.14% for the 30-year GoC bond rates.

**Chart 2 – Difference Between 10-Year Forward GoC Rates and Bond Yield  
 Median Forecast (%)**

Year		Q1	Q2	Q3	Q4
2026	Forward	3.29	3.33	3.37	3.41
	BYFC	3.18	3.20	3.25	3.28
	<b>Difference</b>	<b>(0.12)</b>	<b>(0.13)</b>	<b>(0.12)</b>	<b>(0.14)</b>
2027	Forward	3.45	3.48	3.52	3.55
	BYFC	3.30	3.29	3.33	3.25
	<b>Difference</b>	<b>(0.15)</b>	<b>(0.19)</b>	<b>(0.19)</b>	<b>(0.30)</b>
<b>Average Difference</b>		<b>(0.17)</b>			

**Chart 2A – Difference Between 30-Year Forward GoC Rates and Bond Yield  
 Median Forecast (%)**

Year		Q1	Q2	Q3	Q4
2026	Forward	3.73	3.75	3.76	3.77
	BYFC	3.59	3.60	3.60	3.63
	<b>Difference</b>	<b>(0.15)</b>	<b>(0.15)</b>	<b>(0.16)</b>	<b>(0.15)</b>
2027	Forward	3.78	3.80	3.81	3.82
	BYFC	3.63	3.70	3.70	3.70
	<b>Difference</b>	<b>(0.15)</b>	<b>(0.10)</b>	<b>(0.11)</b>	<b>(0.12)</b>
<b>Average Difference</b>		<b>(0.14)</b>			

Third, as noted at Ex. C1-1-2, p. 6, OPG inferred the BYFC for Q2 2028 to Q4 2031 by applying the average difference as calculated in Charts 2 & 2A above, to the Bloomberg forward GoC rates from Chart 1 & 1A. This calculation is shown in Charts 3 & 3A below.

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**Chart 3 – Bloomberg 10-Year Bond Yield Median Forecast (%)**

Year		Q1	Q2	Q3	Q4
2026	BYFC	3.18	3.20	3.25	3.28
2027	BYFC	3.30	3.29	3.33	3.25
2028	Forward		3.61	3.65	3.67
	Average Difference		(0.17)	(0.17)	(0.17)
	<b>BYFC (inferred)</b>	3.25	<b>3.45</b>	<b>3.48</b>	<b>3.50</b>
2029	Forward	3.69	3.72	3.74	3.76
	Average Difference	(0.17)	(0.17)	(0.17)	(0.17)
	<b>BYFC (inferred)</b>	<b>3.53</b>	<b>3.55</b>	<b>3.57</b>	<b>3.59</b>
2030	Forward	3.78	3.80	3.82	3.83
	Average Difference	(0.17)	(0.17)	(0.17)	(0.17)
	<b>BYFC (inferred)</b>	<b>3.61</b>	<b>3.63</b>	<b>3.65</b>	<b>3.67</b>
2031	Forward	3.85	3.86	3.87	3.88
	Average Difference	(0.17)	(0.17)	(0.17)	(0.17)
	<b>BYFC (inferred)</b>	<b>3.68</b>	<b>3.70</b>	<b>3.71</b>	<b>3.72</b>

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**Chart 3A – Bloomberg 30-Year Bond Yield Median Forecast (%)**

Year		Q1	Q2	Q3	Q4
2026	BYFC	3.59	3.60	3.60	3.63
2027	BYFC	3.63	3.70	3.70	3.70
2028	Forward		3.84	3.85	3.86
	Average Difference		(0.14)	(0.14)	(0.14)
	<b>BYFC (inferred)</b>	3.48	<b>3.70</b>	<b>3.71</b>	<b>3.72</b>
2029	Forward	3.87	3.87	3.88	3.89
	Average Difference	(0.14)	(0.14)	(0.14)	(0.14)
	<b>BYFC (inferred)</b>	<b>3.73</b>	<b>3.74</b>	<b>3.75</b>	<b>3.75</b>
2030	Forward	3.89	3.90	3.91	3.91
	Average Difference	(0.14)	(0.14)	(0.14)	(0.14)
	<b>BYFC (inferred)</b>	<b>3.76</b>	<b>3.76</b>	<b>3.77</b>	<b>3.78</b>
2031	Forward	3.92	3.92	3.92	3.93
	Average Difference	(0.14)	(0.14)	(0.14)	(0.14)
	<b>BYFC (inferred)</b>	<b>3.78</b>	<b>3.78</b>	<b>3.79</b>	<b>3.79</b>

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Fourth, OPG blended equally the Bloomberg forward GoC rates from Chart 1 & 1A above with the BYFC from Chart 3 & 3A above to determine its forecast 10-Year and 30-Year GoC bond rates. This calculation is shown in Charts 4 & 4A below.

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**Chart 4 – Forecast 10-Year GoC Bond Rates (%)**

Year		Q1	Q2	Q3	Q4
2026	Forward	3.29	3.33	3.37	3.41
	BYFC	3.18	3.20	3.25	3.28
	<b>GoC Bond Rate</b>	<b>3.23</b>	<b>3.27</b>	<b>3.31</b>	<b>3.34</b>
2027	Forward	3.45	3.48	3.52	3.55
	BYFC	3.30	3.29	3.33	3.25
	<b>GoC Bond Rate</b>	<b>3.37</b>	<b>3.39</b>	<b>3.42</b>	<b>3.40</b>
2028	Forward	3.58	3.61	3.65	3.67
	BYFC	3.25	3.45	3.48	3.50
	<b>GoC Bond Rate</b>	<b>3.42</b>	<b>3.53</b>	<b>3.56</b>	<b>3.59</b>
2029	Forward	3.69	3.72	3.74	3.76
	BYFC	3.53	3.55	3.57	3.59
	<b>GoC Bond Rate</b>	<b>3.61</b>	<b>3.63</b>	<b>3.66</b>	<b>3.68</b>
2030	Forward	3.78	3.80	3.82	3.83
	BYFC	3.61	3.63	3.65	3.67
	<b>GoC Bond Rate</b>	<b>3.70</b>	<b>3.72</b>	<b>3.74</b>	<b>3.75</b>
2031	Forward	3.85	3.86	3.87	3.88
	BYFC	3.68	3.70	3.71	3.72
	<b>GoC Bond Rate</b>	<b>3.77</b>	<b>3.78</b>	<b>3.79</b>	<b>3.80</b>

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**Chart 4A – Forecast 30-Year GoC Bond Rates (%)**

Year		Q1	Q2	Q3	Q4
2026	Forward	3.73	3.75	3.76	3.77
	BYFC	3.59	3.60	3.60	3.63
	<b>GoC Bond Rate</b>	<b>3.66</b>	<b>3.67</b>	<b>3.68</b>	<b>3.70</b>
2027	Forward	3.78	3.80	3.81	3.82
	BYFC	3.63	3.70	3.70	3.70
	<b>GoC Bond Rate</b>	<b>3.71</b>	<b>3.75</b>	<b>3.75</b>	<b>3.76</b>
2028	Forward	3.83	3.84	3.85	3.86
	BYFC	3.48	3.70	3.71	3.72
	<b>GoC Bond Rate</b>	<b>3.65</b>	<b>3.77</b>	<b>3.78</b>	<b>3.79</b>
2029	Forward	3.87	3.87	3.88	3.89
	BYFC	3.73	3.74	3.75	3.75
	<b>GoC Bond Rate</b>	<b>3.80</b>	<b>3.81</b>	<b>3.81</b>	<b>3.82</b>
2030	Forward	3.89	3.90	3.91	3.91
	BYFC	3.76	3.76	3.77	3.78
	<b>GoC Bond Rate</b>	<b>3.83</b>	<b>3.83</b>	<b>3.84</b>	<b>3.84</b>
2031	Forward	3.92	3.92	3.92	3.93
	BYFC	3.78	3.78	3.79	3.79
	<b>GoC Bond Rate</b>	<b>3.85</b>	<b>3.85</b>	<b>3.86</b>	<b>3.86</b>

In Chart 5 & 5A below, OPG has shown the application of the issuance cost (12 basis points for 10-year and 10 basis points for 30-year tenor) and OPG spread (135 basis points for 10-year and 160 basis points for 30-year tenor) to the forecast GoC bond rates from Chart 4 & 4A above. The derivation of the OPG spread can be found in part c) and the issuance cost in part d), below.

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**Chart 5 – Forecast 10-Year Long-Term Debt Issuance Cost (%)**

Year		Q1	Q2	Q3	Q4
2026	GoC Bond Rate	3.23	3.27	3.31	3.34
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>4.70</b>	<b>4.74</b>	<b>4.78</b>	<b>4.81</b>
2027	GoC Bond Rate	3.37	3.39	3.42	3.40
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>4.84</b>	<b>4.86</b>	<b>4.89</b>	<b>4.87</b>
2028	GoC Bond Rate	3.42	3.53	3.56	3.59
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>4.89</b>	<b>5.00</b>	<b>5.03</b>	<b>5.06</b>
2029	GoC Bond Rate	3.61	3.63	3.66	3.68
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>5.08</b>	<b>5.10</b>	<b>5.13</b>	<b>5.15</b>
2030	GoC Bond Rate	3.70	3.72	3.74	3.75
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>5.17</b>	<b>5.19</b>	<b>5.21</b>	<b>5.22</b>
2031	GoC Bond Rate	3.77	3.78	3.79	3.80
	OPG Spread	1.35	1.35	1.35	1.35
	Issuance Cost	0.12	0.12	0.12	0.12
	<b>Debt Issuance Cost</b>	<b>5.24</b>	<b>5.25</b>	<b>5.26</b>	<b>5.27</b>

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**Chart 5A – Forecast 30-Year Long-Term Debt Issuance Cost (%)**

Year		Q1	Q2	Q3	Q4
2026	GoC Bond Rate	3.66	3.67	3.68	3.70
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.36</b>	<b>5.37</b>	<b>5.38</b>	<b>5.40</b>
2027	GoC Bond Rate	3.71	3.75	3.75	3.76
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.41</b>	<b>5.45</b>	<b>5.45</b>	<b>5.46</b>
2028	GoC Bond Rate	3.65	3.77	3.78	3.79
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.35</b>	<b>5.47</b>	<b>5.48</b>	<b>5.49</b>
2029	GoC Bond Rate	3.80	3.81	3.81	3.82
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.50</b>	<b>5.51</b>	<b>5.51</b>	<b>5.52</b>
2030	GoC Bond Rate	3.83	3.83	3.84	3.84
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.53</b>	<b>5.53</b>	<b>5.54</b>	<b>5.54</b>
2031	GoC Bond Rate	3.85	3.85	3.86	3.86
	OPG Spread	1.60	1.60	1.60	1.60
	Issuance Cost	0.10	0.10	0.10	0.10
	<b>Debt Issuance Cost</b>	<b>5.55</b>	<b>5.55</b>	<b>5.56</b>	<b>5.56</b>

c) OPG has provided in Chart 6 & 6A below its three-year average historical indicative new issue credit spreads, obtained from each of the six major Canadian banks as of November 21, 2025, for the respective tenors that underpin the credit spread values used by OPG to forecast its cost of long-term debt in Ex. C1-1-2.

**Chart 6 – OPG Historical Indicative New 10-Year Long-Term Debt Issue Credit Spreads Sourced from Major Banks (bps)**

	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>Average</b>
Bank A	163	135	112	<b>138</b>
Bank B	162	129	110	<b>135</b>
Bank C	165	133	111	<b>137</b>
Bank D	163	130	109	<b>135</b>
Bank E	156	130	108	<b>132</b>
Bank F	160	131	112	<b>135</b>
<b>Average</b>	<b>162</b>	<b>131</b>	<b>110</b>	<b>135</b>

**Chart 6A – OPG Historical Indicative New 30-Year Long-Term Debt Issue Credit Spreads Sourced from Major Banks (bps)**

	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>Average</b>
Bank A	184	163	136	<b>162</b>
Bank B	182	159	136	<b>160</b>
Bank C	184	161	136	<b>161</b>
Bank D	185	161	135	<b>161</b>
Bank E	178	158	133	<b>157</b>
Bank F	179	160	136	<b>159</b>
<b>Average</b>	<b>182</b>	<b>160</b>	<b>136</b>	<b>160</b>

d) OPG has provided the historical data supporting the issuance costs included in the forecast long-term debt rates in Chart 7 & 7A below. Informed by the EB-2024-0063 Decision and Order, p. 76, OPG has calculated issuance cost using the effective interest rate methodology by taking the average difference between the effective and coupon rate of OPG's debt issuances since establishing its Medium-Term Notes program in 2017.

**Chart 7 – Issuance Cost for 10-Year Long-Term Debt (%)**

Settlement Date	Maturity Date	Coupon Rate	Effective Rate	Difference
October 2017	October 2027	3.32	3.43	<b>0.11</b>
September 2019	September 2029	2.98	3.07	<b>0.09</b>
April 2020	April 2030	3.22	3.31	<b>0.10</b>
July 2022	July 2032	4.92	5.08	<b>0.16</b>
June 2024	June 2034	4.83	4.98	<b>0.14</b>
March 2025	March 2035	4.32	4.45	<b>0.13</b>
<b>Average</b>				<b>0.12</b>

**Chart 7A – Issuance Cost for 30-Year Long-Term Debt (%)**

Settlement Date	Maturity Date	Coupon Rate	Effective Rate	Difference
June 2018	June 2048	3.84	3.92	<b>0.08</b>
January 2019	January 2049	4.25	4.34	<b>0.09</b>
September 2019	September 2050	3.65	3.72	<b>0.07</b>
February 2021	February 2051	2.95	3.01	<b>0.06</b>
June 2024	June 2054	4.99	5.17	<b>0.18</b>
March 2025	March 2055	4.87	4.97	<b>0.11</b>
<b>Average</b>				<b>0.10</b>

e) As at April 21, 2026, the 10-year and 30-year GoC rates were 3.50% and 3.91%, respectively.

f) Refer to Ex. L-C1-Staff-033, part (c).

g) The average OPG historical indicative new 10-year and 30-year long-term debt issue credit spreads sourced from the six major banks as of November 17, 2025 were, respectively, 1.02% and 1.24%.

For the reasons discussed in Ex. C1-1-2, p. 6 and Ex. L-C1-Staff-031, OPG believes that basing the credit spread on a historical average, rather than a single observation point of one day, improves the forecasting accuracy and is therefore superior in its use in forecasting OPG's cost of planned debt issues.

**CCC Interrogatory #036**

**Interrogatory**

**Reference:**

**Exhibit C1, Tab 1, Schedule 3, pp. 1-3**

**Exhibit C1, Tab 1, Schedule 3, Table 2**

**Question(s):**

- a) Please provide the calculations underpinning the interest rates shown in Line 2 of Table 2.
- b) Please provide the historical information supporting the 17-basis point corporate spread over the OIS rate.
- c) Please provide the short-term debt rate for the 2027-2031 period based on the previous approach applied by OPG (i.e., Global Insight forecast).
- d) Please advise whether the 10-basis point dealer fee is still applied in OPG's updated approach to establishing the short-term debt rate.
- e) Please provide the calculation supporting the bank credit facility fees for each year of the 2027-2031 period.

**Response**

- a) The interest rates for 2020-2024 shown at Ex. C1-1-3, Table 2, line 2 are the actual weighted average interest rates on OPG's company-wide outstanding commercial paper for each year. The calculation of the interest rates is demonstrated in Chart 1 below, by dividing the commercial paper cost by the commercial paper amount.

In the course of preparing the response to this interrogatory, OPG identified a data display error in Ex. C1-1-3, Table 2, line 2, col. (c), whereby the interest rate should display as 0.00% rather than 0.79%. The same applies to Ex. C1-1-1, Table 10, line 1, col. (c). There is no impact of this revision to any other information presented in the Application.

**Chart 1 – Short-Term Interest Rate Calculation for 2020-2024 (\$M)**

	2020	2021	2022	2023	2024
Commercial Paper Amount (Ex. C1-1-3, Table 2, line 1)	207.5	9.0	0.0	13.8	150.2
Commercial Paper Cost (Ex. C1-1-3, Table 2, line 3)	1.5	0.0	0.0	0.7	7.2
<b>Interest Rate</b>	<b>0.70%</b>	<b>0.21%</b>	<b>0.00%</b>	<b>5.20%</b>	<b>4.79%</b>

To show the calculation of the forecast short-term debt interest rates for 2026-2031, OPG has first included the monthly 3-month Bloomberg Overnight Index Swap (“OIS”) forward rates and the quarterly 3-month T-Bill rate from the Bloomberg Bond Yield Median Forecast (“BYFC”) in Charts 2 & 2A below, which were used to derive the average annual benchmark rates.

**Chart 2 – Monthly and Average Annual 3-Month OIS Forward Rate (%)**

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	2.20	2.18	2.16	2.15	2.14	2.16	2.17	2.19	2.22	2.25	2.28	2.28
	<b>2.20</b>											
2027	2.28	2.28	2.35	2.43	2.50	2.51	2.51	2.51	2.54	2.58	2.61	2.61
	<b>2.48</b>											
2028	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.65	2.69	2.74	2.75
	<b>2.64</b>											
2029	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.78	2.83	2.87	2.88
	<b>2.78</b>											
2030	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.93	2.99	3.05	3.06
	<b>2.93</b>											
2031	3.06	3.06	3.06	3.06	3.06	3.06	3.06	3.06	3.11	3.16	3.22	3.22
	<b>3.10</b>											

**Chart 2A – Quarterly and Average Annual Bloomberg 3-Month T-Bill Median Forecast (%)**

Year	Q1	Q2	Q3	Q4
2026	2.20	2.20	2.25	2.25
	<b>2.23</b>			
2027	2.33	2.53	2.70	2.74
	<b>2.57</b>			

Second, in Chart 3 below, OPG has calculated the difference between the annual Bloomberg forward rates from Chart 2 above, and the BYFC from Chart 2A above for 2026 and 2027. The average difference was 0.06%.

**Chart 3 – Difference Between 3-Month OIS Forward Rate and T-Bill Rate from the Bloomberg Bond Yield Median Forecast (%)**

	2026	2027
Forward	2.20	2.48
BYFC	2.23	2.57
<b>Difference</b>	<b>0.03</b>	<b>0.10</b>
<b>Average Difference</b>	<b>0.06</b>	

Third, as noted at Ex. C1-1-3, p. 6, OPG inferred the BYFC for 2028 to 2031 by applying the average difference as calculated in Chart 3, to the Bloomberg forward rates from Chart 2. OPG has included this calculation in Chart 4 below.

**Chart 4 – Bloomberg 3-Month T-Bill Rate from the Bloomberg Bond Yield Median Forecast (%)**

	2026	2027	2028	2029	2030	2031
Forward			2.64	2.78	2.93	3.10
Average Difference			0.06	0.06	0.06	0.06
<b>BYFC (inferred in 2028-2031)</b>	2.23	2.57	<b>2.70</b>	<b>2.84</b>	<b>2.99</b>	<b>3.16</b>

Lastly, OPG blended equally the Bloomberg forward rates from Chart 2 above with the BYFC from Chart 4 above to determine the short-term benchmark rate. OPG then applied the OPG corporate spread (17 basis points) and dealer fee (10 basis points) to the benchmark rate to calculate the short-term debt interest rate. This calculation is shown in Chart 5 below. The derivation of the OPG corporate spread can be found in part b) below.

**Chart 5 – OPG’s Forecast Cost of Short-term Debt (%)**

	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>	<b>2030</b>	<b>2031</b>
Forward	2.20	2.48	2.64	2.78	2.93	3.10
BYFC	2.23	2.57	2.70	2.84	2.99	3.16
<b>Benchmark Rate</b>	<b>2.21</b>	<b>2.52</b>	<b>2.67</b>	<b>2.81</b>	<b>2.96</b>	<b>3.13</b>
Corporate Spread	0.17	0.17	0.17	0.17	0.17	0.17
Dealer Fee	0.10	0.10	0.10	0.10	0.10	0.10
<b>Interest Rate</b>	<b>2.47</b>	<b>2.79</b>	<b>2.93</b>	<b>3.07</b>	<b>3.22</b>	<b>3.39</b>

- b) OPG has provided in Chart 6 below its average 3-month tenor commercial paper issuance spreads since the OIS rate became the benchmark for commercial paper in June 2024, replacing banker’s acceptance. For clarity, OPG had no 3-month commercial paper issuances in 2024.

**Chart 6 – OPG Historical New Commercial Paper Issue Credit Spreads**

<b>Settlement Date</b>	<b>Maturity Date</b>	<b>Days Outstanding</b>	<b>Corporate Spread (basis points)</b>
02/03/2025	05/07/2025	93	24
02/03/2025	05/07/2025	93	24
02/06/2025	05/14/2025	97	18
02/12/2025	05/21/2025	98	14
03/05/2025	06/04/2025	91	16
06/23/2025	09/24/2025	93	20
06/23/2025	09/24/2025	93	20
06/25/2025	10/01/2025	98	15
07/17/2025	10/15/2025	90	9
08/06/2025	10/29/2025	84	11
08/06/2025	10/29/2025	84	11
08/20/2025	11/12/2025	84	14
09/03/2025	12/03/2025	91	21
09/03/2025	12/08/2025	96	21
<b>Average</b>			<b>17</b>

- c) Refer to Ex. L-C1-Staff-038, part c).
- d) Confirmed.
- e) OPG has included the calculation for the bank credit facility fees shown at Ex. C1-1-3, Table 2, line 4 for 2027-2031, in Chart 7 & 8 below. As noted in Ex. C1-1-3, p.

3, OPG has “anticipated future facility needs to meet the liquidity requirement set by the credit rating agencies.” OPG has assumed any incremental capacity will be in the form of a bank credit facility denominated in Canadian dollars, and incremental fees have been based on the fees of the existing Canadian dollar bank credit facility shown below.

**Chart 7 – Facility Cost (\$M)**

	2027	2028	2029	2030	2031
Existing Capacity	3,300	3,300	3,300	3,300	3,300
Incremental Capacity	1,700	700	700	0	0
<b>Total Capacity</b>	<b>5,000</b>	<b>4,000</b>	<b>4,000</b>	<b>3,300</b>	<b>3,300</b>
Existing Fees	7.1	7.1	7.1	7.1	7.1
Incremental Fees	4.3	1.8	1.8	0.0	0.0
<b>Total Fees</b>	<b>11.4</b>	<b>8.9</b>	<b>8.9</b>	<b>7.1</b>	<b>7.1</b>

**Chart 8 – Existing Facility Cost (\$M)**

Facility	Existing Facility
Bank CAD	1,000
Bank USD	750
OFA <sup>1</sup> CAD	1,250
<b>Total CAD</b>	<b>3,300</b>

<sup>1</sup> Refers to OPG’s credit facility with the Ontario Financing Authority.

**SEC Interrogatory #038**

**Interrogatory**

**Reference:  
C1-1-1, Attachment 3**

Question(s):

Please provide details and a copy of any analysis that OPG undertook regarding its ability to secure debt financing for the DNNP within 12-18 months following the in-service date of the first unit.

**Response**

OPG consulted with its investment banking advisors regarding the timing and feasibility of securing non-recourse debt financing for DNNP LP. [REDACTED]

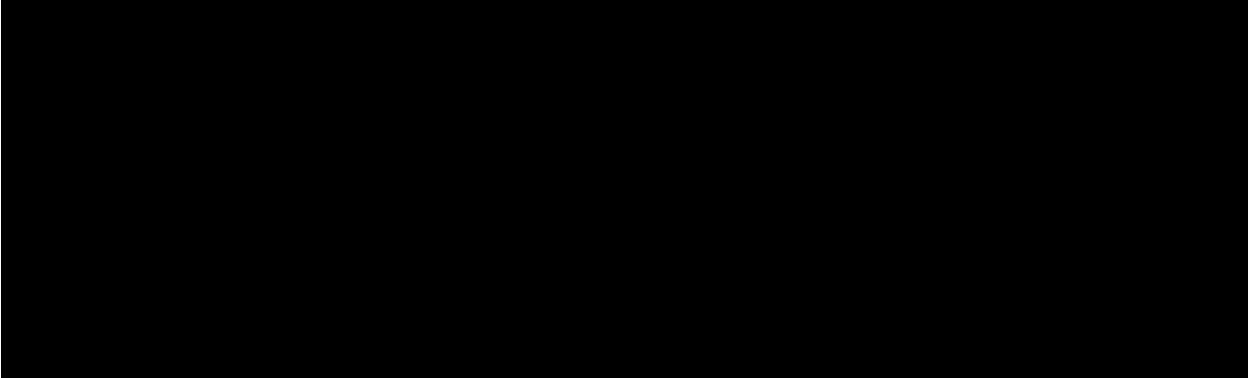
[REDACTED]

A copy of the analysis is provided in Attachment 1 [REDACTED]

[REDACTED]

[REDACTED]

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*Privileged and Confidential*

# Financing New Nuclear Construction

**ONTARIO**POWER  
GENERATION

March 27, 2026

**CIBC** 

Filed: 2026-04-24, EB-2025-0297  
Exhibit L-C1-SEC-038  
Attachment 1, Page 1 of 15



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All currencies are in Canadian Dollars unless otherwise stated.



# Executive Summary

## Introduction & Observations

### Key Takeaways

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Expected Ratings  
Outcomes

Financing Decision and  
Rationale

Capital Markets & Timing  
Implications

# Darlington New Nuclear Project Overview

## First Grid-Scale Small Modular Reactor in the G7

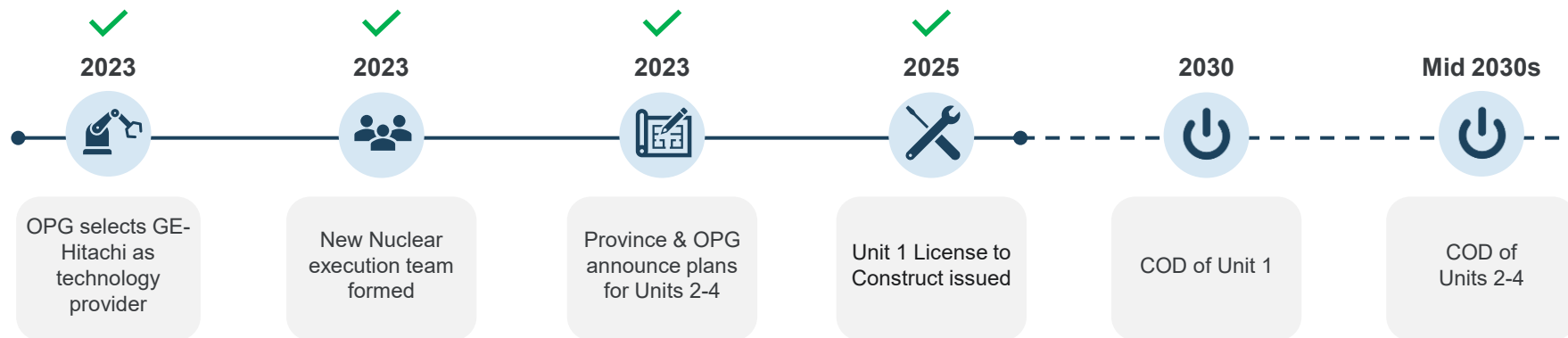
### Project Overview

- Ontario Power Generation's ("OPG") Darlington New Nuclear Project ("DNNP") is a four-unit, 1,200 MW small modular reactor ("SMR") project, to be constructed at OPG's Darlington nuclear site
  - DNNP will consist of up to four GE Hitachi BWRX-300 reactors (300 MW each)
  - OPG expects to complete construction of Unit 1 by the end of the decade and connect it to the grid by the end of 2030, with construction on Units 2-4 expected to be completed in the mid-2030s<sup>1</sup>
  - The project is expected to cost \$20.9bn<sup>1</sup>, including site preparation, engineering, design work to date, and construction of all four reactors over an anticipated period of 10 years
  - DNNP received its License to Construct for Unit 1 in April 2025. DNNP's environmental assessment was approved in 2012 and affirmed in 2024<sup>2</sup>. Both are prerequisites to nuclear construction

### Key Project Challenges

<b>Cost Uncertainty</b>	<ul style="list-style-type: none"> <li>As the first grid-scale SMR project in the G7, DNNP lacks cost benchmarking and precedent builds, making estimates less reliable</li> </ul>
<b>Construction Timeline Risk</b>	<ul style="list-style-type: none"> <li>First nuclear construction in Canada in over 30 years</li> <li>Potential delays from regulatory, supply chain, and workforce challenges unique to FOAK projects</li> </ul>
<b>Technology Risk</b>	<ul style="list-style-type: none"> <li>DNNP uses enriched uranium, unlike other Canadian nuclear facilities, introducing operational complexities</li> <li>FOAK technology at this scale may face unforeseen performance, safety, or reliability issues</li> </ul>

### Project Timeline



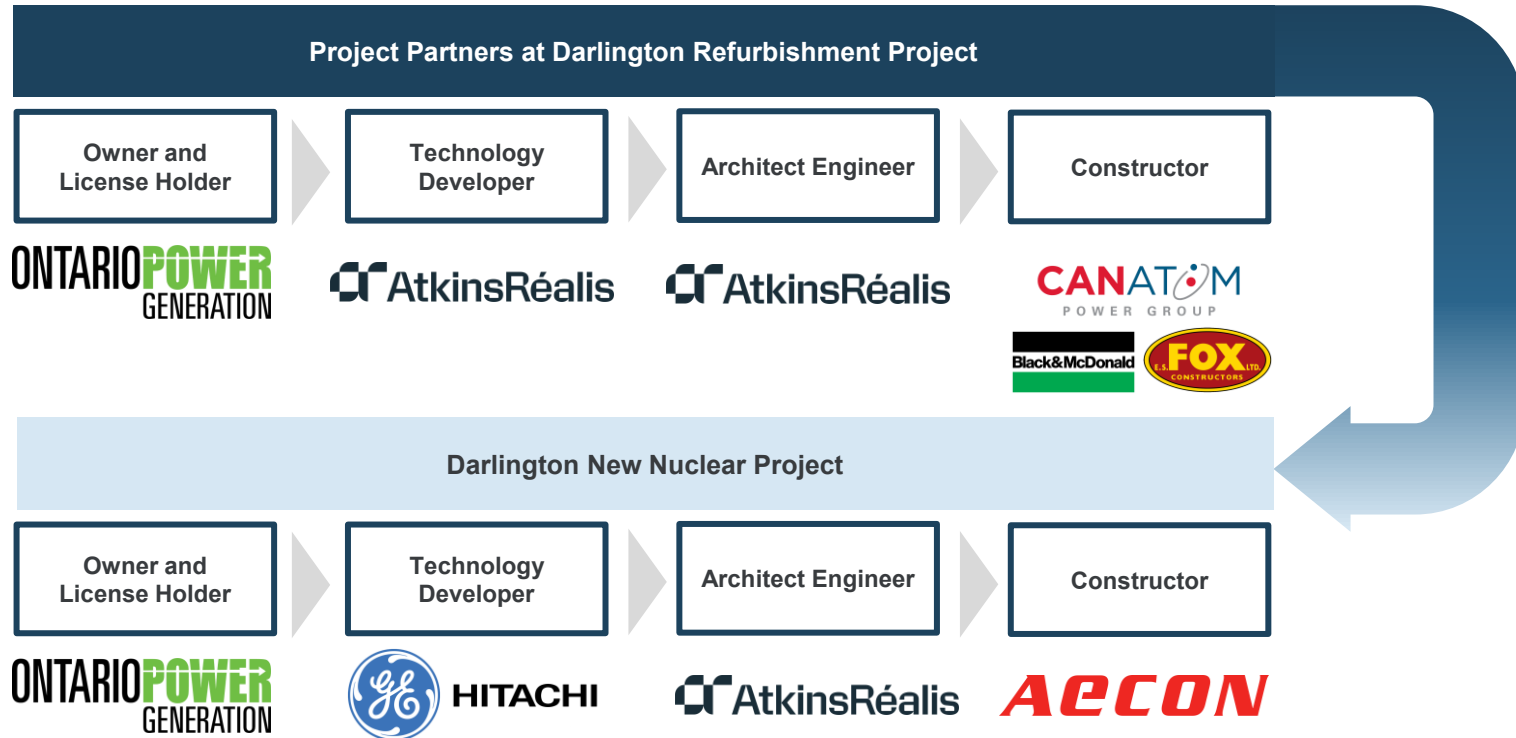
<sup>1</sup> Source: Press Release.

<sup>2</sup> The DNNP's environmental assessment was approved in 2012. In 2024, the Canadian Nuclear Safety Commission affirmed that the existing environmental assessment is applicable to the selected reactor technology.

# Project Delivery on DNNP



## Top-Tier Delivery Partners Supporting OPG on this FOAK Project

- OPG has partnered with GE Hitachi, Aecon and AtkinsRéalis to deliver the Darlington New Nuclear Project
  - OPG has previous experience partnering with AtkinsRéalis on its underbudget, ahead of schedule delivery of the Darlington Refurbishment Program



# Integrated Project Delivery Model at DNNP

## Parties & Scope

 (Owner)	<ul style="list-style-type: none"> <li>Defines the project requirement</li> <li>Engineer and project management lead</li> <li>Provides certain reference information to the Non-Owner Parties</li> <li>Undertakes CNSC licensing activities</li> </ul>
 (Designer)	<ul style="list-style-type: none"> <li>Performs reactor design and engineering work</li> <li>Procures key equipment (e.g. reactor pressure vessel and steam turbine generator)</li> </ul>
 (Architect Engineering Firm)	<ul style="list-style-type: none"> <li>Performs the detailed site design and engineering work</li> </ul>
 (Constructor)	<ul style="list-style-type: none"> <li>Executes constructor and support commissioning</li> <li>Procures specified equipment and materials</li> </ul>

Non-Owner Parties

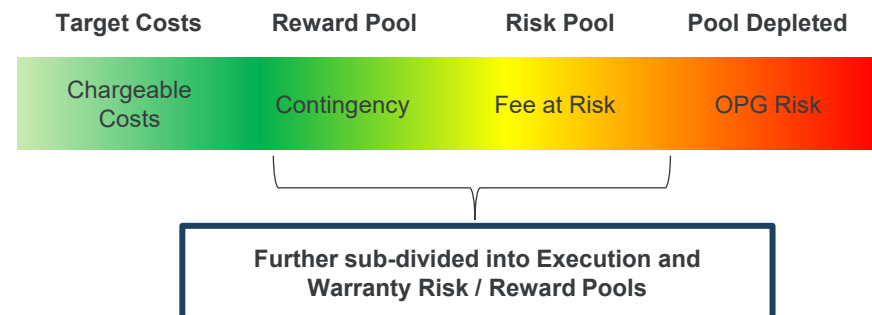
## Pricing Structure and Incentive Model

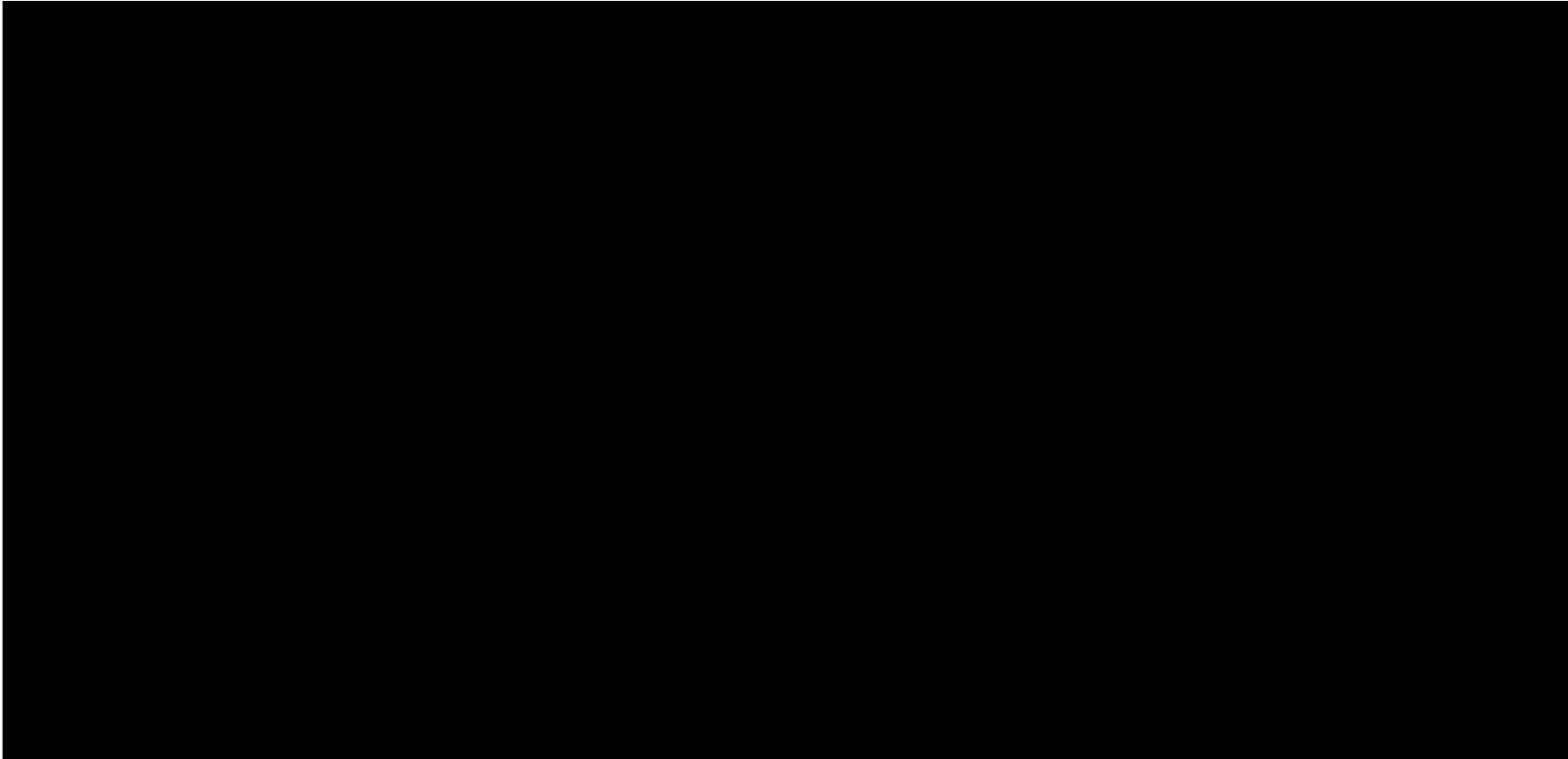
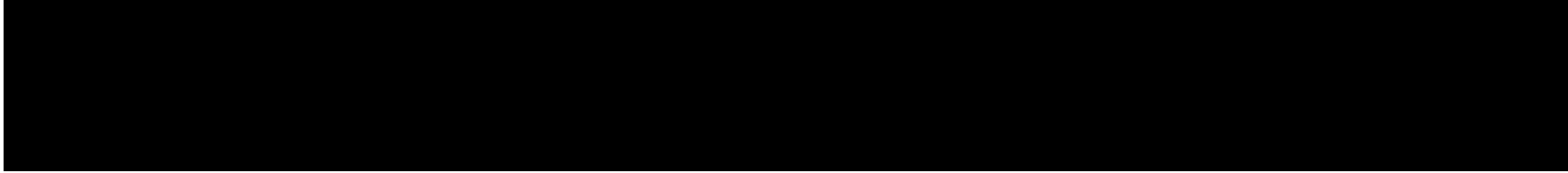
**The Non-Owner Parties are compensated for their work on DNNP through**

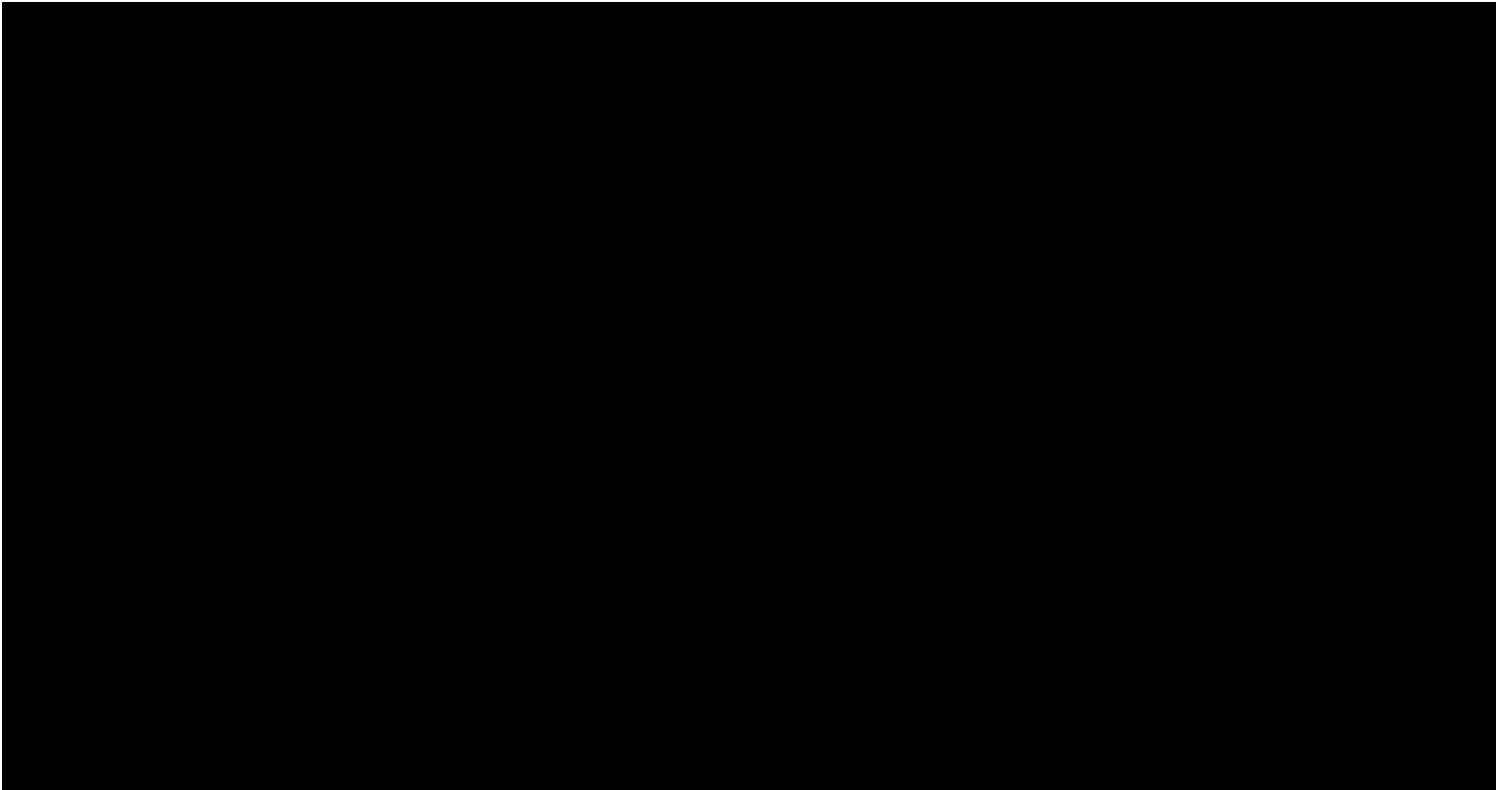
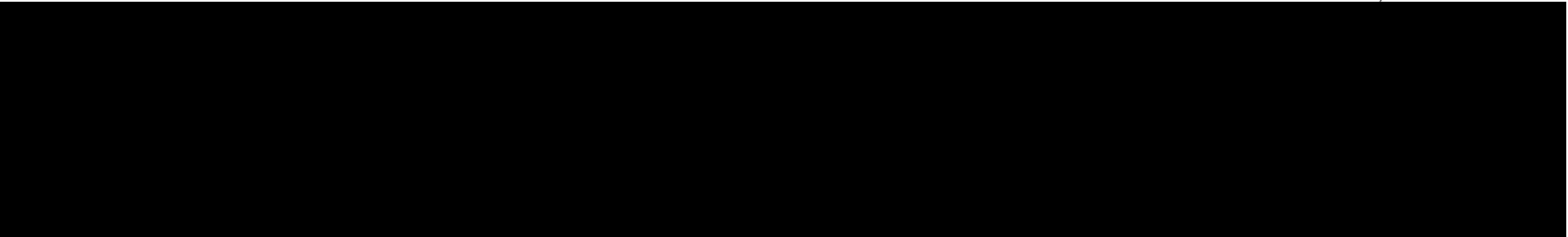
1. Monthly payments for their allowed, direct, project-specific base costs incurred and a portfolio of their overhead calculated as a specified percentage for categories of costs
2. The operation of the Risk/Reward Pool

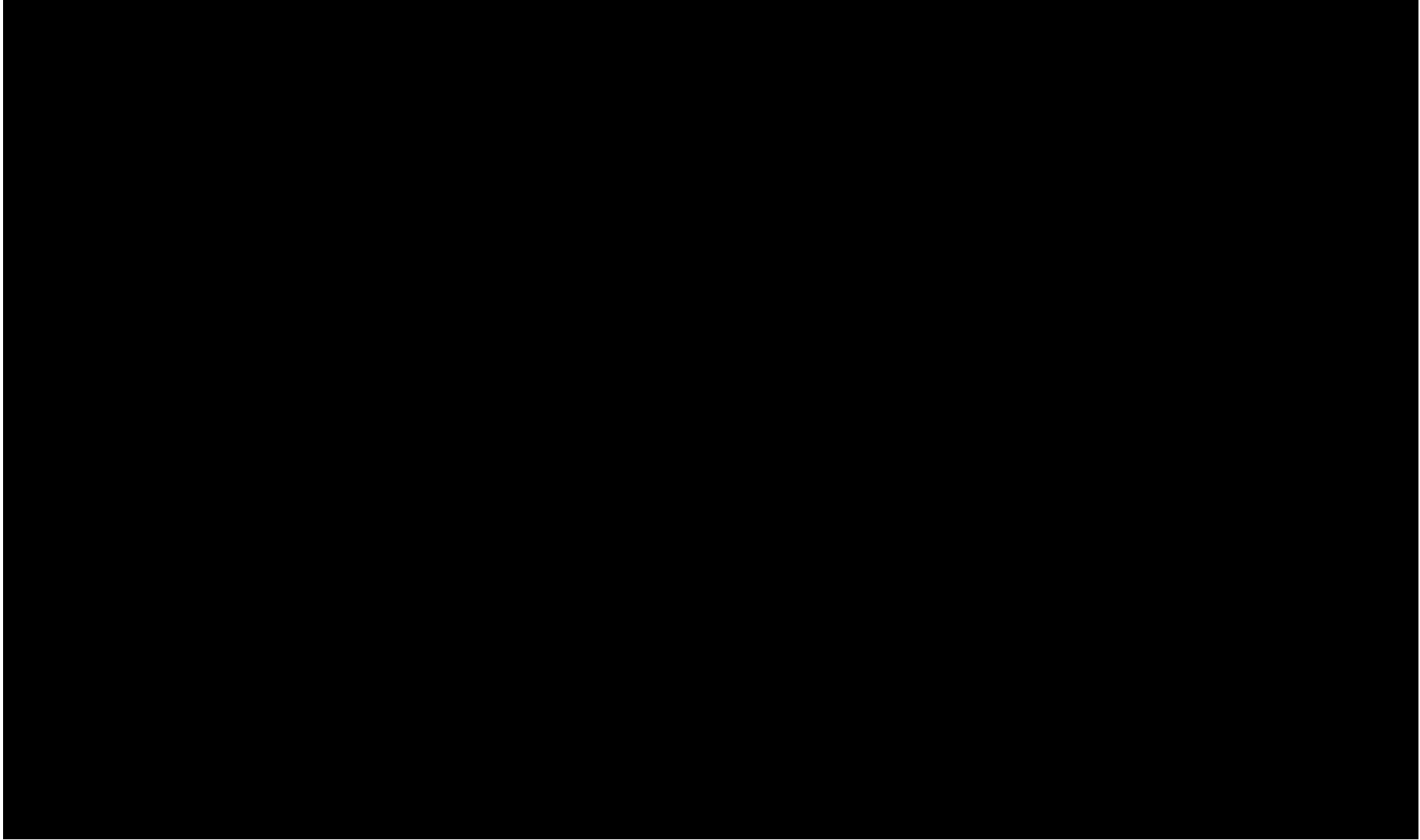
**The IPA incentivizes the partners to meet budget and schedule through the Risk/Reward pool**

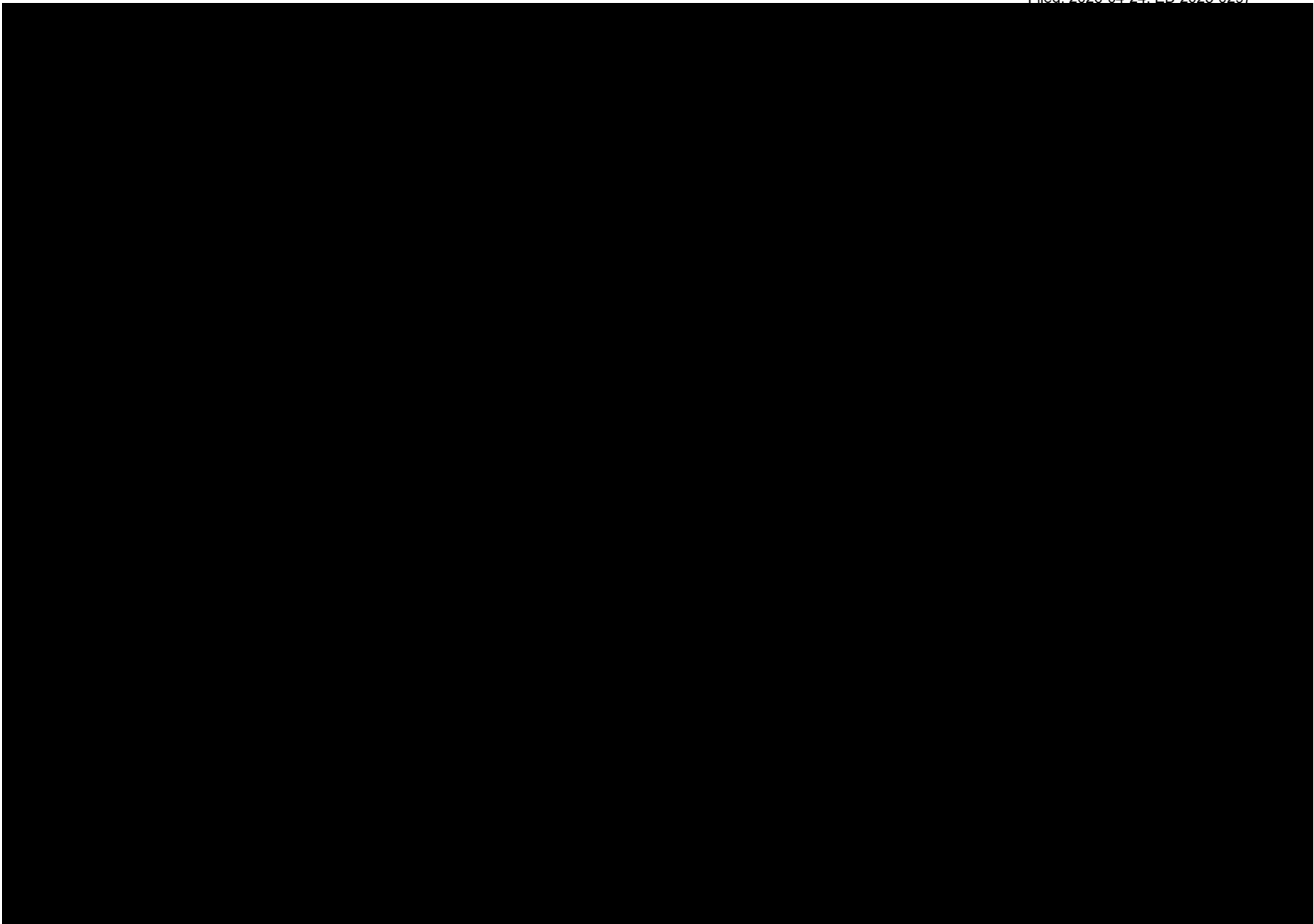
1. Reward pool set through project contingency funded by the Owner
2. Risk pool reflecting amounts at risk funded by the partners from their Profit and Overheads

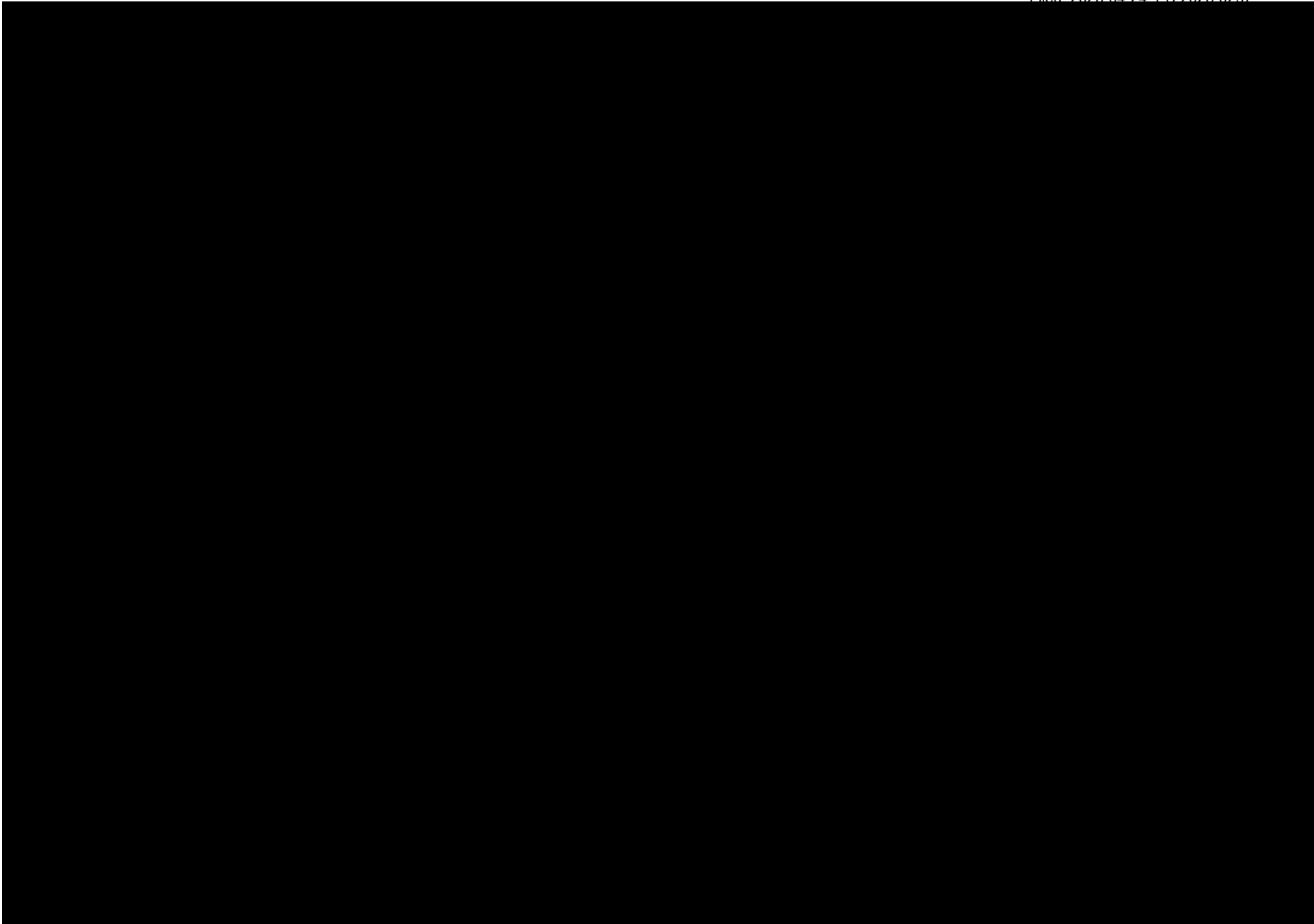


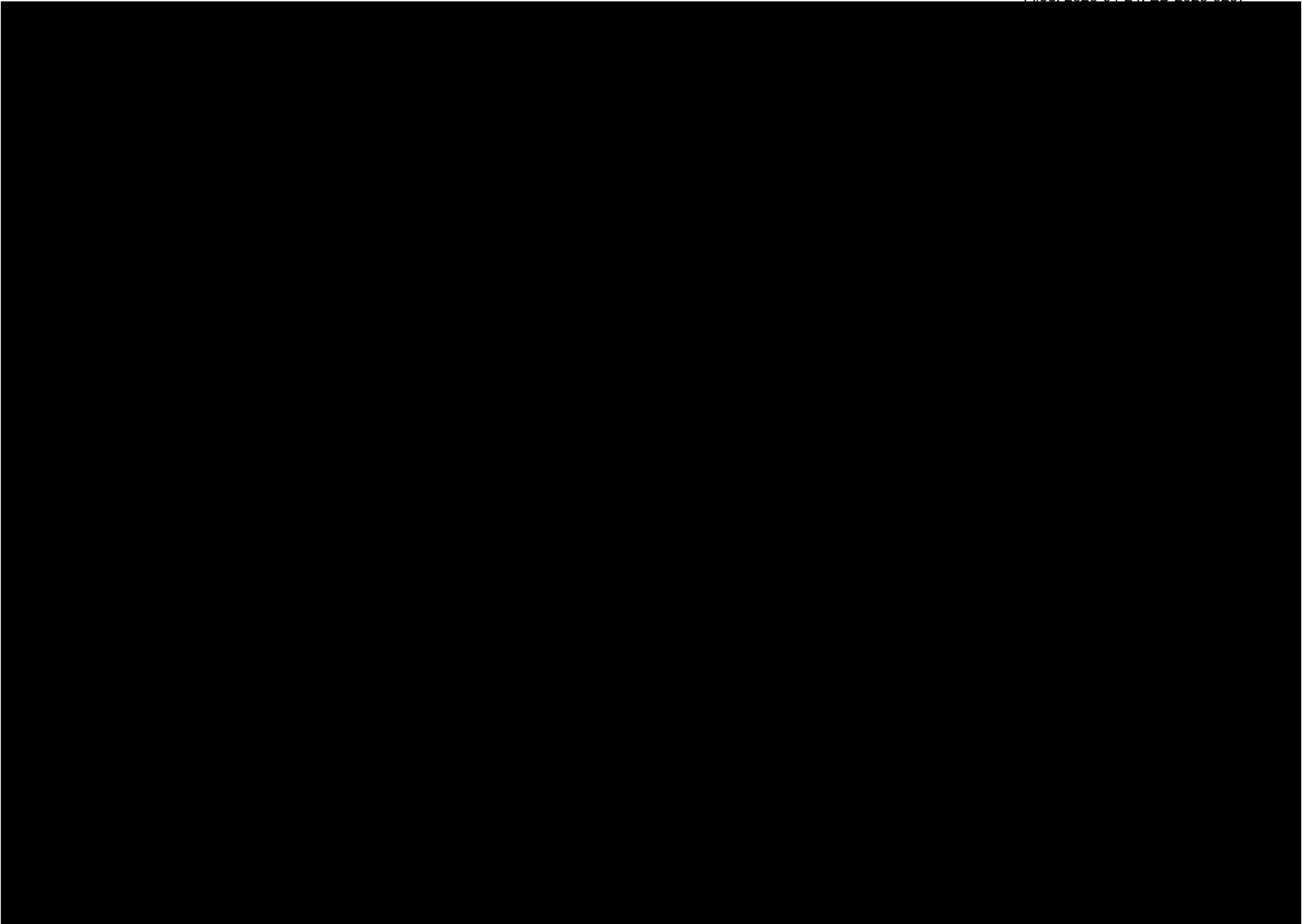


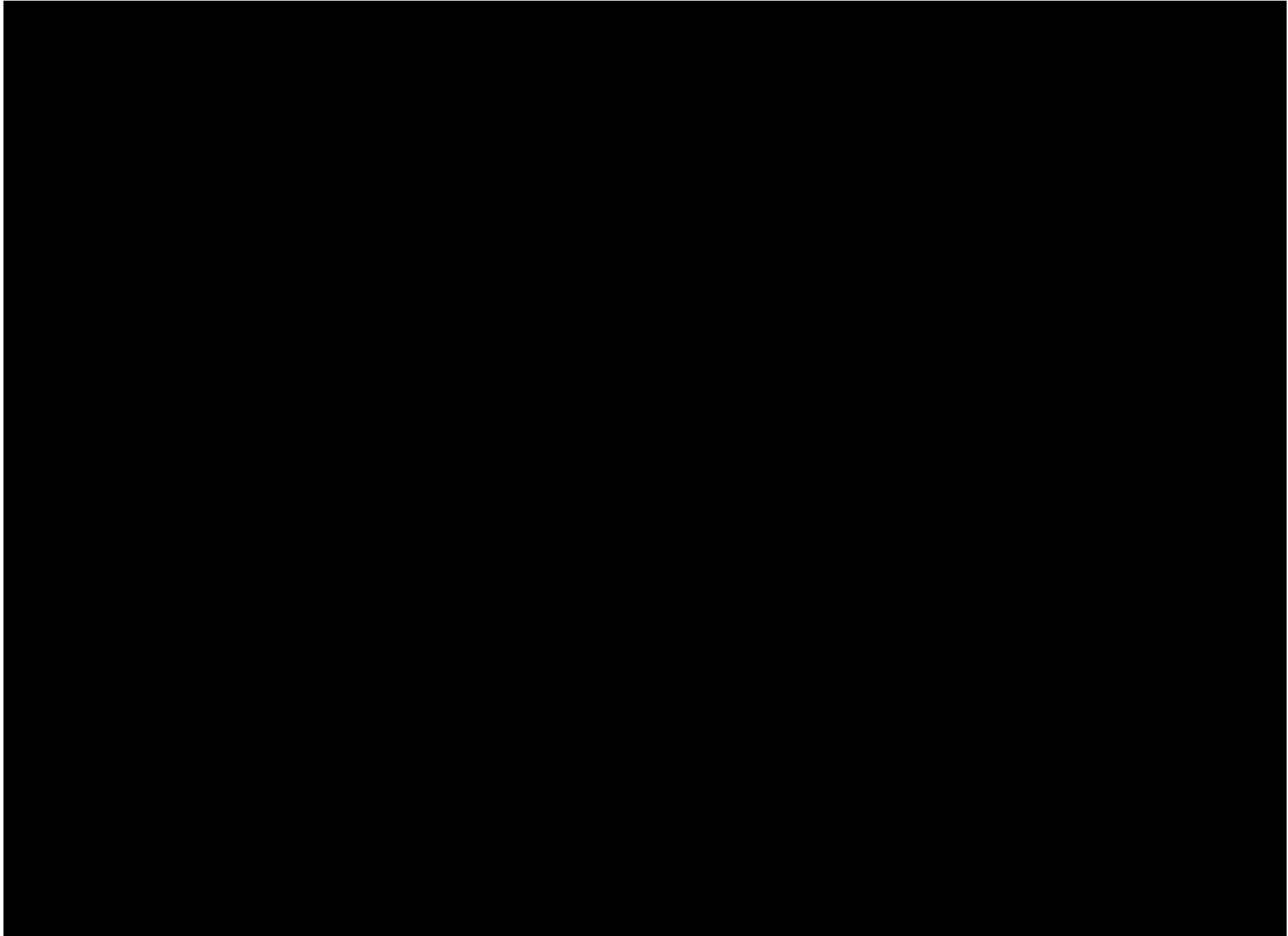


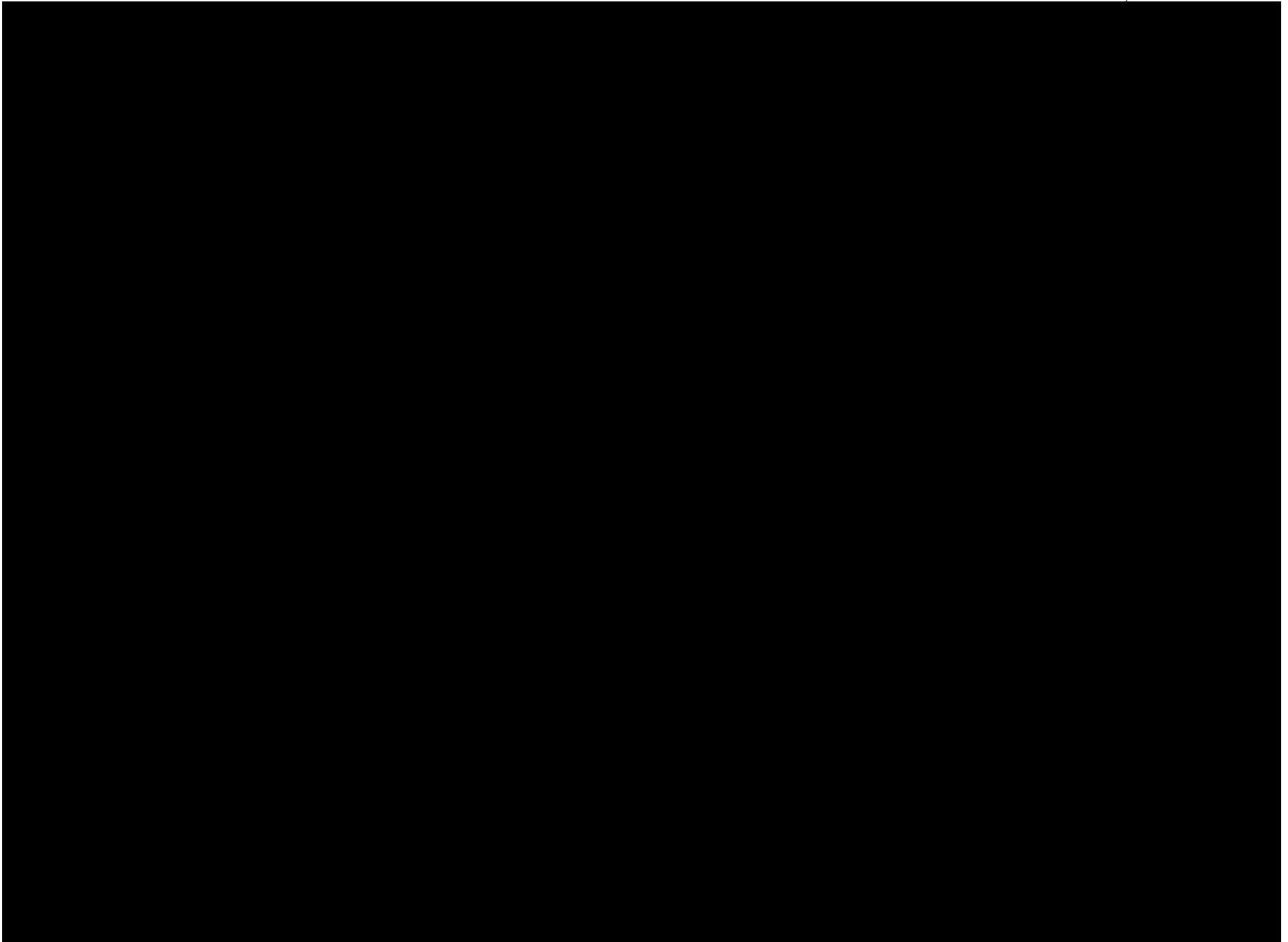


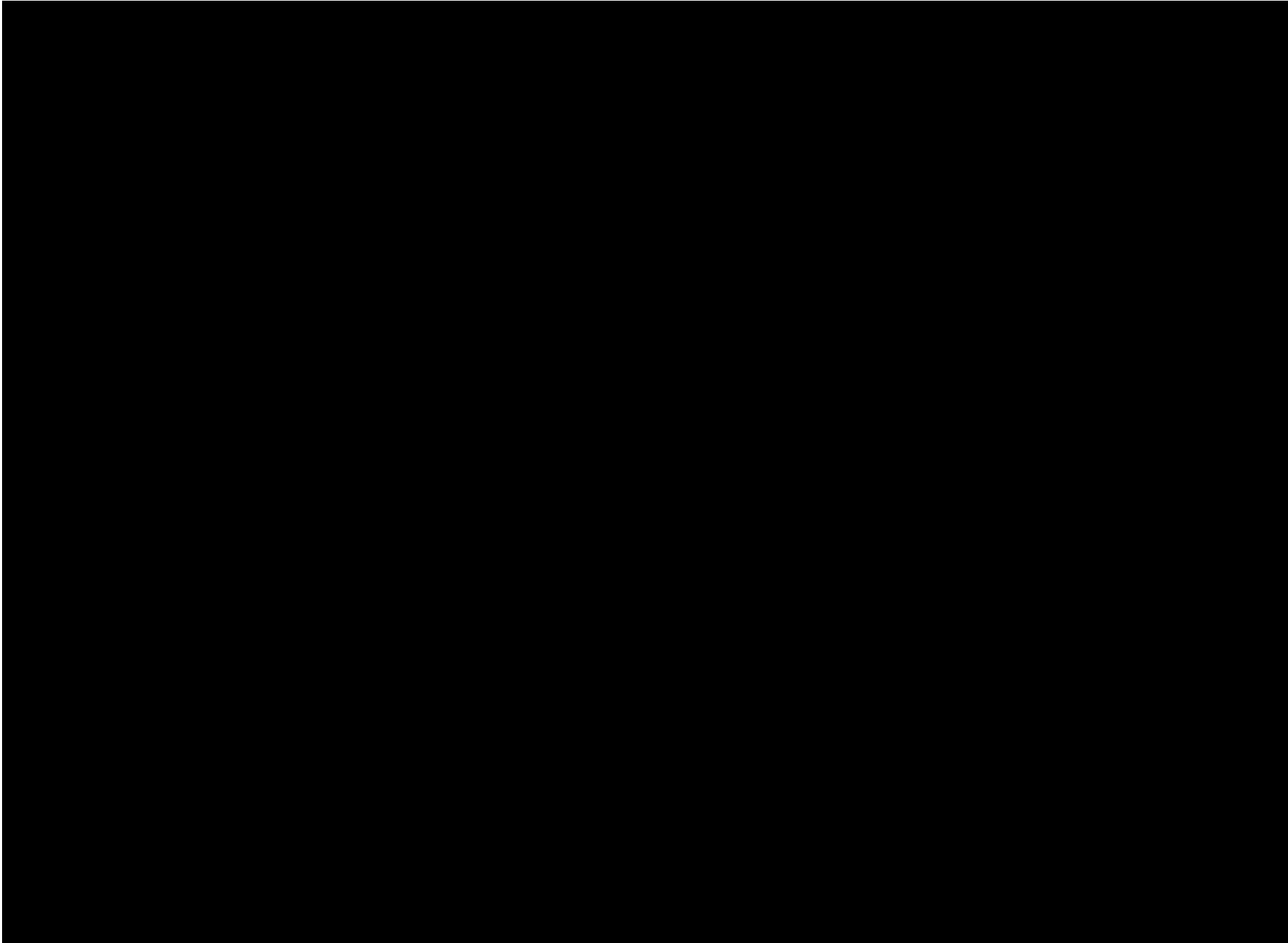












**SEC Interrogatory #039**

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**Interrogatory**

**Reference:  
C1-1-2, p. 7-8**

Question(s):

Please provide all underlying calculations used to forecast the Government of Canada Bond Rates set out in Chart 1 and 1A, and the Issuance Costs set out in Chart 2 and 2A.

**Response**

Refer to Ex. L-C1-CCC-35 part b).

**SEC Interrogatory #040**

**Interrogatory**

**Reference:**  
**C1-1-2, p. 9**

Preamble:

The evidence states: "The debt outstanding under the CIB facility will remain with OPG following the transfer of the DNNP facilities to DNNP LP. As discussed above, as it will no longer be associated with OPG's prescribed facilities, this debt is excluded from that attributed to OPG's regulated operations. Instead, under the expected partnership arrangements, OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026."

Question(s):

- a) Please provide the details of the CIB Facility.
- b) Please explain what is meant by the "net financial impact" resulting from the outstanding CIB debt facility and how they can be a charge or credit.
- c) Please provide an estimate of the potential credit or charge.
- d) Are the costs, charged or credited, to DNNP LP recoverable from ratepayers, if so, please provide how and when?

**Response**

a) As stated in Ex. C1-1-2, Section 4.5, "[i]n 2022, OPG entered into a \$970 million non-revolving term credit facility with the CIB. The facility was made available to fund part of the expenditures required to prepare for the construction of the DNNP", including project design, site preparation, procurement of long lead-time equipment, utility connections, implementation of a digital strategy, and related project management costs. The availability period to borrow under the facility ended in August 2025. The facility has customary covenants that are generally aligned with OPG's existing bond indenture and bank credit facilities, with the addition of certain project-specific and other covenants (e.g., limit on use of loan proceeds for the purposes as noted above).

. As at December 31, 2025, \$711 million

1 was outstanding under the facility. The interest rates on the outstanding amounts  
2 can be found at Ex. C1-1-2, Table 7 (confidential).  
3

4 b) Refer to Ex. L-A1-CCC-010, Attachment 4, p. 65 for the definition of the net financial  
5 impact that constitutes the referenced credit (or charge) pursuant to the  
6 Management, Operations, Maintenance and Administration Agreement between  
7 OPG and DNNP LP.  
8

9 c) The referenced amount, as embedded at Ex. F2-1-1, line 7 in the Application, is a  
10 forecast credit to DNNP LP for all years 2026-2031, as follows:  
11

	2026	2027	2028	2029	2030	2031
\$M	(4.3)	(7.0)	(9.9)	(11.5)	(11.1)	(4.3)

12  
13 d) As discussed at Ex. L-C1-Staff-032, the referenced credit (or charge) forms part of  
14 the operating costs payable by DNNP LP to OPG under the Management,  
15 Operations, Maintenance and Administration Agreement in place between the  
16 parties in respect of services being provided by OPG in respect of the DNNP  
17 facilities and is therefore treated as refundable to (or recoverable from) ratepayers  
18 on the same basis as other components of DNNP LP's OM&A costs. As noted in  
19 part c) above, such forecast credit for all years of the 2027-2031 IR term has been  
20 included as a reduction of DNNP LP's proposed revenue requirements in the  
21 Application.

**Board Staff Interrogatory #028**

**Interrogatory**

**Reference:**

**Ref 1: EB-2024-0063, Generic Cost of Capital Decision and Order, March 27, 2025, pp. 71, 80, 81**

**Preamble:**

In the generic cost of capital decision, the OEB stated that for OPG, neither the deemed long-term debt rate (DLTDR) or deemed short-term debt rate (DSTDR) will be applied as a cap on the unfunded portion of the capital structure (the portion of the capital structure to reach 100%). The OEB noted that it will assess whether the cost of debt has been prudently incurred, and the DLTDR and DSTDR will be considered as part of that assessment.

The OEB also stated that OPG is expected to demonstrate that it has been prudent in its debt management. In determining that prudence, the OEB will assess the management of debt and the processes the utility has in place to manage their treasury functions.

**Question(s):**

- a) Please explain how OPG's costs of long-term debt included in its 2027-2031 revenue requirements have been prudently incurred, in the context of the OEB's DLTDR of 4.73% set for 2026 rates.
- b) Please explain how OPG's costs of short-term debt included in its 2027-2031 revenue requirements have been prudently incurred, in the context of the OEB's DSTDR of 2.72% set for 2026 rates.
- c) Please explain how OPG has been prudent in its debt management, including its management of debt and the processes OPG has in place to manage its treasury functions.

**Response**

- a) OPG's costs of long-term debt included in its proposed 2027-2031 revenue requirements reflect the weighted average of its actual embedded costs of outstanding long-term debt and the forecast embedded costs of new long-term debt issuances over the 2026-2031 period, as attributed to the regulated operations.

1 These costs have been and continue to be prudently incurred. The long-term debt  
2 cost rates reflected in the proposed revenue requirements are 4.58% for 2027,  
3 4.78% for 2028, 4.90% for 2029, 4.97% in 2030 and 4.98% in 2031.<sup>1</sup> These cost  
4 rates are applied to both the existing/planned long-term debt and the other (i.e.,  
5 unfunded) long-term debt components of the proposed capital structure. This  
6 approach to determining long-term debt costs, which is based on a forecast of the  
7 Government of Canada (“GoC”) bond rates for the applicable tenor and an  
8 observed OPG credit spread, has been applied in all prior OPG payment amounts  
9 proceedings and accords to the OEB’s EB-2024-0063 Decision and Order.

10  
11 In particular, the EB-2024-0063 Decision and Order states:

12  
13 The OEB concludes it is appropriate to use utilities’  
14 embedded cost of debt and forecast of debt in setting rates,  
15 just like it uses actual fixed assets and forecast capital  
16 expenditures in establishing a rate base. [...] The OEB  
17 remains of the view that there should be greater reliance  
18 on actual and forecast embedded debt costs for the utilities,  
19 as was stated in the 2009 Report. When debt is market-  
20 based, there is greater assurance to the OEB that the cost  
21 of debt is reasonable. (p. 72)

22  
23 Similar to Enbridge Gas, the OEB finds that the current  
24 approach for determining debt costs — applying actual and  
25 forecast debt costs for issued long-term debt and a forecast  
26 of short-term debt rates to the forecast amount of short-  
27 term debt — for the rebasing period continues to be  
28 appropriate for determining OPG’s debt cost of capital. (p.  
29 67)

30  
31 For OPG and Enbridge Gas, the DLTD R will not be applied  
32 as a cap on the unfunded portion of the capital structure  
33 (the portion of the capital structure to reach 100%). The  
34 OEB will assess whether the cost of debt has been  
35 prudently incurred, and the DLTD R will be considered as  
36 part of that assessment. OPG and Enbridge Gas are  
37 expected to demonstrate that they have been prudent in  
38 their debt management. In determining that prudence, the  
39 OEB will assess the management of debt and the  
40 processes the utility has in place to manage their treasury  
41 functions. (p. 71)

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<sup>1</sup> As calculated at Ex. C1-1-2, Tables 9-13.

1 The costs of all OPG's actual embedded long-term debt have been determined by  
2 market conditions at the time of issuance. As set out in Ex. C1-1-2, the majority of  
3 OPG's long-term debt outstanding has been issued under its Medium-Term Note  
4 Program, which provides access to the public debt markets. The costs of historical  
5 debt outstanding with the Ontario Electricity Financial Corporation were also  
6 established by market conditions, as they were set using a prevailing benchmark  
7 GoC bond for the corresponding tenor and a credit margin based on quotes  
8 provided by a group of Canadian banks.<sup>2</sup> Additional information on OPG's debt  
9 management practices is provided in part c) below.

10  
11 As discussed in Ex. C1-1-2, Section 4.2, OPG continues to apply a market-based  
12 methodology to forecasting new long-term debt issuance costs, using forecasted  
13 GoC bond yields for the applicable tenor and an observed credit spread. This  
14 provides a transparent and supportable basis for establishing a prudent cost of  
15 long-term debt for revenue requirement purposes. In addition to using a market-  
16 based approach, as discussed at the above evidence and as further explained at  
17 Ex. L-C1-Staff-029 and Ex. L-C1-Staff-031, OPG has reflected several additional  
18 updates and improvements to the forecasting methodology in this Application,  
19 including adopting a mix of both 10-year and 30-year interest rate forecasts to better  
20 reflect the historical and planned issue tenors as well as introducing the use of  
21 consensus forecasts and forward rates published by Bloomberg. These changes  
22 enhance forecasting accuracy and transparency. The forecasts of OPG's new long-  
23 term debt issuance costs can be found at Ex. C1-1-2, Charts 2 and 2A. The amount  
24 and timing of the forecast issuances is based on OPG's 2025-2031 Business Plan,  
25 excluding financing related to OPG's unregulated operations.

26  
27 Like other issuers, OPG's cost of embedded long-term debt is influenced by its  
28 credit ratings, which have to date remained at the same levels as in the prior  
29 payment amounts proceeding (refer to Ex. A2-3-1). Consistent with OPG's 2025-  
30 2031 Business Plan, the Application assumes that OPG will be successful in  
31 maintaining the current ratings over the IR term. A discussion of credit supportive  
32 funding sources that are helping to manage OPG's borrowing requirements and  
33 maintain credit ratings can be found in Ex. L-A2-SEC-024.

34  
35 With respect to the DLTD of 4.73% for 2026, OPG observes that it is not  
36 comparable to either the weighted average cost of OPG's long-term debt reflected  
37 in the proposed revenue requirements nor the cost of OPG's new long-term debt  
38 issues underpinning such weighted average cost.

39  
40 First, the DLTD reflects market conditions at a given point in time – in this case  
41 as of September 2025 – whereas OPG's weighted average cost of debt reflects the  
42 embedded cost of both historical and future issues, each reflecting the realized or

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<sup>2</sup> EB-2020-0290, Ex. C1-1-2, p. 4, lines 6-11.

1 projected market conditions at the time debt is issued. The forecast component of  
2 the weighted average cost is dependent on when an issuance is expected to take  
3 place, with the pre-filed evidence projecting no new debt issues partially or fully  
4 attributable to the regulated operations until 2027. OPG's methodology for  
5 forecasting the cost of long-term debt takes into account the forecasted timing of  
6 future issuances and is therefore more accurate than the simplified approach of  
7 DLTDR.

8  
9 Second, both the DLTDR and DSTDR reference the Bloomberg BVCAUA Index  
10 (ticker: BVSC0090 Index), which is the yield curve that represents the yields across  
11 the term structure for Canadian A-rated utilities ("Bloomberg A-rated utilities  
12 index"). The DLTDR references the 30-year tenor of the Bloomberg A-rated utilities  
13 index (ticker: BVCAUA30 BVLI Index). The DSTDR references the 3-month tenor  
14 of the Bloomberg A-rated utilities index (ticker: BVCAUA3M BVLI Index).

15  
16 As of April 15, 2026, the constituents within this Bloomberg A-rated utilities index<sup>3</sup>  
17 comprised of bonds issued by:

- 18 • Alectra Inc
- 19 • Canadian Utilities Ltd
- 20 • CU Inc
- 21 • Enbridge Gas Inc
- 22 • EPCOR Utilities Inc
- 23 • FortisAlberta Inc
- 24 • FortisBC Energy Inc
- 25 • Hydro One Inc
- 26 • Hydro One Ltd
- 27 • Toronto Hydro Corp.

28  
29 OPG is not a constituent of the Bloomberg A-rated utilities index, but rather part of  
30 the BVCAUB Index ("Bloomberg BBB-rated utilities index"). As of April 15, 2026,  
31 the constituents within the Bloomberg BBB-rated utilities index<sup>4</sup> comprised of bonds  
32 issued by:

- 33 • AltaGas Ltd
- 34 • ATCO Ltd
- 35 • Brookfield Infrastructure Finance ULC
- 36 • Brookfield Renewable Partners LP
- 37 • Bruce Power LP
- 38 • Capital Power Corp
- 39 • Emera Inc

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<sup>3</sup> Refer to Attachment 1 on how to access the constituent bonds for the Bloomberg A-rated utilities index.

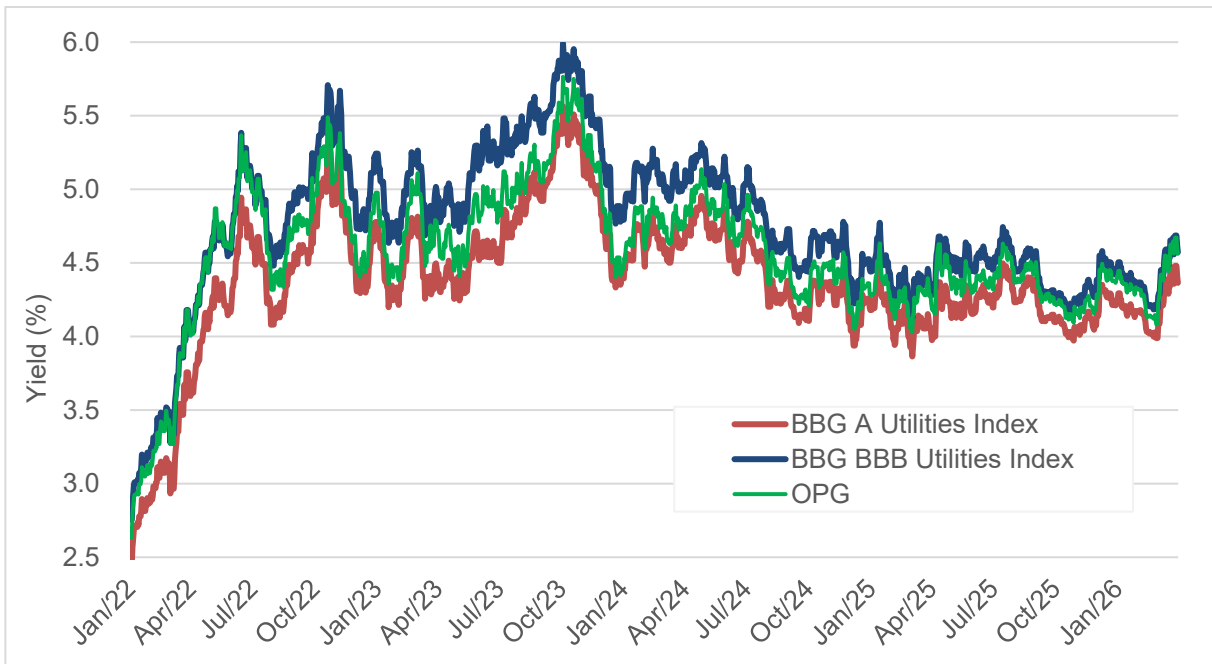
<sup>4</sup> Refer to Attachment 1 on how to access the constituent bonds for the Bloomberg BBB-rated utilities index.

- 1 • ENMAX Corp
- 2 • Fortis Inc
- 3 • FortisBC Inc
- 4 • Nova Scotia Power Inc
- 5 • **Ontario Power Generation Inc**
- 6 • Trisummit Utilities Inc.

7 Chart 1 & 1A below show the yields for the Bloomberg A-rated utilities index, the  
8 Bloomberg BBB-rated utilities index, and OPG for both the 10-year and 30-year  
9 tenors over the period from January 1, 2022 to March 31, 2026. Over this period,  
10 the average difference between the Bloomberg A-rated utilities index and the  
11 Bloomberg BBB-rated utilities index was 35 basis points. In this same period, the  
12 average difference between the Bloomberg A-rated utilities index and OPG's 30-  
13 year indicative new issue bond rate was 23 basis points.  
14

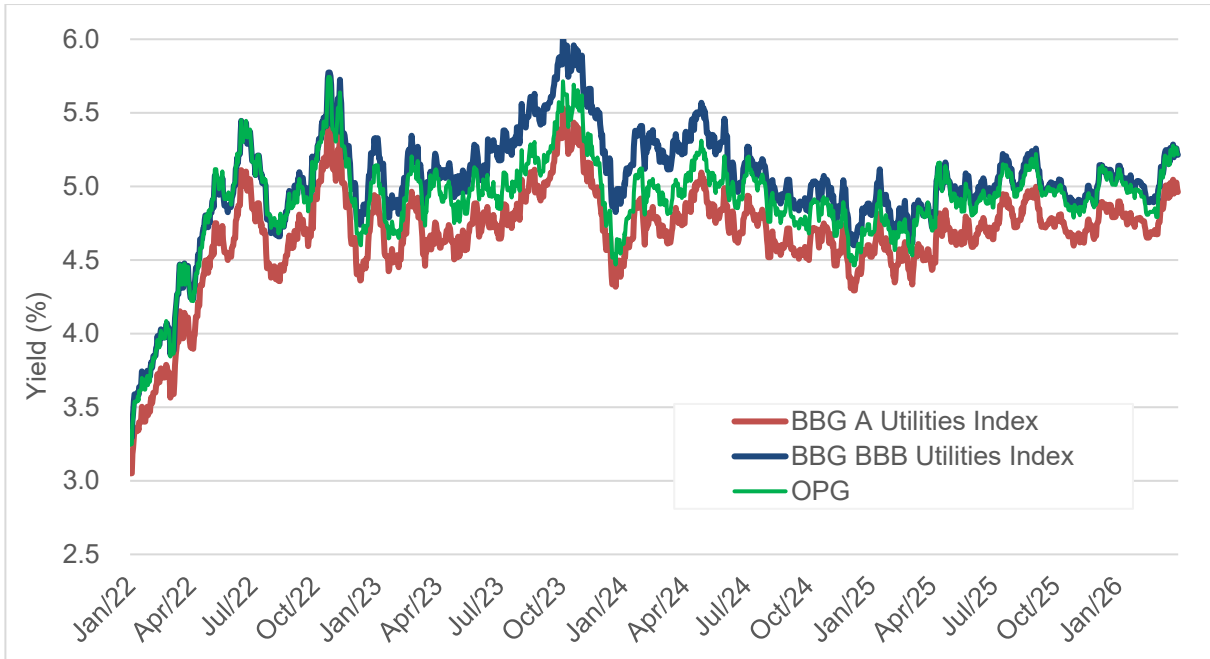
15 **Chart 1 – All-In Rate Comparison for 10-Year Yields**

16



17

1  
2  
**Chart 1A – All-In Rate Comparison for 30-Year Yields**



3  
4  
5 The above phenomenon is further illustrated at Ex. C1-1-1, Attachment 1, pp. 50-  
6 51. That evidence show the difference between new issue credit spread indications  
7 on select A-rated utilities provided by six Canadian banks, versus OPG’s new issue  
8 credit spreads.<sup>5</sup> A similar historical differential of approximately 20 basis points, on  
9 average, is observed in OPG’s credit spread versus those A-rated utilities in this  
10 analysis.

11  
12 The foregoing demonstrates that there are structural differences between OPG’s  
13 credit rating and those of the A-rated utilities, and therefore between OPG’s cost of  
14 long-term debt and the DLTD, such that the DLTD is not an appropriate measure  
15 of OPG’s cost of long-term debt. Instead, it continues to be appropriate to rely on  
16 the embedded cost of OPG’s long-term debt for revenue requirement purposes, the  
17 prudence of which is supported by OPG’s pre-filed evidence and interrogatory  
18 responses.

19  
20 b) OPG’s costs for short-term debt included in the proposed 2027-2031 revenue  
21 requirements reflect the forecast embedded costs of short-term debt expected to

<sup>5</sup> Using select A-rated utilities’ new issue credit spreads as the basis for comparison to OPG’s new issue credit spreads differs from using the Bloomberg Index approach, but helps to provide an alternative perspective. The Bloomberg index approach relies on already-issued bonds trading in the secondary markets, whereas new issue credit spreads represent the Canadian banks’ professional estimates of companies’ credit spreads for new bond issuances. Regardless of the basis of comparison, OPG’s credit spreads remain wider than the A-rated utility peer groups.

1 be outstanding over the IR period, as attributed to the regulated operations. These  
2 costs have been and continue to be prudently incurred. The short-term debt cost  
3 rates reflected in the proposed revenue requirements are 2.79% for 2027, 2.93%  
4 for 2028, 3.07% for 2029, 3.22% in 2030 and 3.39% in 2031.<sup>6</sup> The approach to  
5 determining these short-term debt costs has been applied in all prior OPG payment  
6 amounts proceeding and accords to the OEB's EB-2024-0063 Decision and Order.  
7

8 As discussed in Ex. C1-1-3, OPG's short-term debt comprises a commercial paper  
9 (CP) program, backstopped by credit facilities. Like long-term debt issuances, the  
10 cost of the CP program is determined by market conditions. In addition to being  
11 used as a liquidity backstop, as part of prudent treasury management, OPG's credit  
12 facilities (i) provide liquidity support in the event that the company is unable to issue  
13 either short-term or long-term funding due to a market disruption, and (ii) meet  
14 credit rating agencies' requirements, in support of credit ratings, for ensuring  
15 available sources of liquidity meet projected uses over a near term horizon; the fees  
16 associated with having these facilities available are included in the total short-term  
17 debt cost.  
18

19 As discussed in Ex. C1-1-3, Section 3.0, similar to the long-term debt costs  
20 forecast, OPG continues to apply a market-based methodology to forecasting  
21 short-term debt cost rates, by using a forecasted "risk free" rate and an observed  
22 corporate spread. This provides a transparent and supportable basis for  
23 establishing a prudent cost of short-term debt for revenue requirement purposes.  
24 In addition to using a market-based approach, as discussed at the above evidence  
25 and as further explained at Ex. L-C1-CCC-036 and Ex. L-C1-Staff-036, OPG has  
26 reflected several additional updates and improvements to the forecasting  
27 methodology in this Application, including transitioning to the use of forecasted  
28 overnight index swap ("OIS") and T-Bill rates as well as introducing the use of  
29 consensus forecasts and forward rates published by Bloomberg. In addition to  
30 being necessary to address the phasing out of bankers' acceptance rates in June  
31 2024, these changes enhance forecasting accuracy and transparency. Like long-  
32 term debt, OPG's cost of embedded short-term debt is influenced by its existing  
33 credit ratings.  
34

35 With respect to the DSTDR of 2.72% for 2026, OPG observes that it is higher than  
36 OPG's forecast cost of short-term debt of 2.47% and is not comparable to OPG's  
37 forecast costs. Similar to the DLTD, the DSTDR reflects market conditions at a  
38 given point in time – as of September 2025 – whereas OPG's forecast cost of short-  
39 term debt is more accurate in that it takes into account the forecasted market  
40 conditions that may impact CP issuances. Additionally, as discussed in part a)  
41 above, the DSTDR is based on the Bloomberg A-rated utilities index for the 3-month

---

<sup>6</sup> As shown in Ex. C1-1-3, Table 2, line 2.

1 tenor, whereas OPG does not form part of the constituent bonds for this index and  
2 is instead part of the Bloomberg BBB-rated utilities index.

3  
4 Further, regardless of whether the Bloomberg A-rated or BBB-rated index is being  
5 utilized, the indices at the 3-month tenor are not a good representation of the cost  
6 of OPG's CP issuances because they do not consider CP issuances or other forms  
7 of short-term debt (e.g., bank credit facilities) as part of their constituents. Instead,  
8 the shorter-term portion (e.g., 3-month tenor) of the indices' yield curve term  
9 structure is largely informed by a small number of previously-issued long-term  
10 bonds that have since "crawled down" into the 3-month tenor.<sup>7</sup> OPG's CP program  
11 has distinct investors compared to those in its long-term bond program, as CP  
12 investors have different investment preferences compared to investors in long-term  
13 bonds. As such, different pricing dynamics are observed in these markets, which  
14 can lead to yields on CP being different compared to the previously-issued long-  
15 term bonds that have a similar remaining term to maturity.

16  
17 When considering the DSTDR and the Bloomberg A-rated utilities index, OPG's  
18 proposed short-term debt corporate spread of 17 basis points ("bps") over the 3-  
19 month OIS rate is lower than the equivalent spreads for both the Bloomberg A-rated  
20 utilities index and the Bloomberg BBB-rated utilities index for the 3-month tenor as  
21 observed since June 2024 when OIS became the benchmark for CP rates  
22 (respectively, 28 bps and 51 bps).

23  
24 Given the differences between the basis of the DSTDR and the nature of OPG's  
25 short-term debt, OPG's current approach to forecasting the short-term debt costs  
26 is a more appropriate representation of its future funding costs. OPG believes it is  
27 prudent to continue to rely on its embedded short-term debt costs, rather than the  
28 DSTDR, for revenue requirement purposes.

29  
30 c) OPG manages its debt with the objective of ensuring that it has sufficient liquidity  
31 to meet its expected use of funds on a timely basis and at a reasonable cost  
32 corresponding to its investment grade rating. Key aspects of OPG's management  
33 of the short-term and long-term debt portfolio include:

- 34  
35 • Assessing cash balances and near-term funding gap for working capital,  
36 including monitoring cash inflows compared to forecasted expenditures and  
37 upcoming debt maturities in the coming days, weeks, and months. This  
38 assessment is performed by integrating current bank account balance data,  
39 accounts payables/receivables data, updates from internal business units, and

---

<sup>7</sup> For example, as of April 15, 2026 only three bonds existed within the index's constituents that had remaining maturities of less than one year. Two of these bonds were issued by Enbridge Gas Inc. in 1996 and 2016, and the other bond was issued by Toronto Hydro Corporation in 2016. Among these three bonds, only two of them had remaining term to maturity near the 3-month tenor (the Enbridge Gas Inc. bond due August 5, 2026 with CUSIP 29290ZAR1 and the Toronto Hydro Corporation bond due August 25, 2026 with CUSIP 89119ZAJ2).

1 OPG's business plan. This information is used to inform the need for any near-  
2 term cash replenishment activities which would typically be completed through  
3 short-term debt issuances (e.g., CP).  
4

- 5 • For short-term debt, OPG primarily uses its CP program as backed by  
6 committed bank credit facilities. OPG issues CPs with staggered maturities that  
7 align with expected cash inflows and outflows, ensuring efficient and timely  
8 funding. By maintaining strong investor relationships, working with multiple  
9 banks, actively monitoring market conditions, and holding sufficient liquidity  
10 buffers, OPG aims to position its CP program as a reliable and cost-efficient  
11 short-term funding vehicle. Further to both the CP program and the committed  
12 bank credit facilities, OPG also maintains credit facilities with the Ontario  
13 Financing Authority ("OFA") and the Ontario Electricity Financial Corporation  
14 ("OEFC"), as discussed in Ex. C1-1-3, p. 1. As discussed elsewhere in this  
15 response, these facilities provide additional liquidity cushion and in combination  
16 with the committed bank credit facilities, serve to ensure that credit rating  
17 agencies' liquidity adequacy requirements are met.  
18
- 19 • Assessing longer term funding requirements (over a 12+ month period), which  
20 considers cash balances and expected revenue and cashflows over a longer  
21 period, compared to expected capital expenditures and debt maturities within  
22 this timeframe, typically utilizing OPG's business plan as a key input into the  
23 assessment. This assessment allows OPG to plan the number and size of debt  
24 issuances expected to be required over the next 12-24 months.  
25
- 26 • Once OPG determines the number of long-term debt issuances expected to be  
27 required over the next 12–24-month period, OPG monitors current and  
28 prospective market conditions across several asset classes, including interest  
29 rates and credit spreads across the key tenors in which OPG typically issues,  
30 and across different currencies given the interconnected nature of financial  
31 markets. OPG considers information observed from the actual primary market  
32 and secondary market trading activity across the broader capital markets, as  
33 well as from economic forecast sources, to help inform treasury decisions. This  
34 includes monitoring for market-moving geopolitical risk events, and their  
35 potential impact to the broader short-term and long-term funding markets. OPG  
36 plans its funding activities to avoid significant known events (including but not  
37 limited to pre-scheduled central bank meeting dates, market-moving economic  
38 data releases, or government elections) that could have a negative impact to  
39 market conditions and result in more expensive debt through higher credit  
40 spreads.  
41
- 42 • OPG conducts ongoing and robust fixed income investor relations activities  
43 ahead of any potential long-term debt issuances to help achieve optimal

1 investor receptivity on the day of bond issuance. OPG has conducted just under  
2 300 investor meetings and attended just under 20 fixed income investor events  
3 hosted by since EB-2020-0290. The purpose of these meetings is to ensure that  
4 on bond issuance day, investors can enter the deal execution process with  
5 confidence in OPG, helping to facilitate the necessary funding at a competitive  
6 spread.  
7

- 8 • On the day of bond issuance, OPG begins by engaging a syndicate of banks  
9 which provide their views on optimal tenors, timing, and execution strategy to  
10 achieve the required funding size in the most cost-effective manner. These  
11 views are based on recent market transactions on which the banks have  
12 recently advised, as well as outreach that bank syndicate desks have with  
13 investors on a regular basis. The banks will also consider the market conditions  
14 that manifest on the day of issuance, and any expected competing supply that  
15 may impact OPG's execution. Once execution timing, tenors, and indicative  
16 pricing have been aligned between OPG and the syndicate of banks, the  
17 expected top 10-20 investors are "soft-sounded", where indicative pricing and  
18 size objectives are discussed to collect feedback. Based on this feedback, if  
19 required, pricing is further adjusted, and the deal is launched publicly for all  
20 institutional fixed income investors to participate by submitting their order size  
21 and price floors. Final pricing is determined based on the lowest price at which  
22 the required amount of bonds can be issued. In the final orderbook, OPG has  
23 in recent bond issuances typically attracted between 40-60 investors. By  
24 considering pricing/spread and sizing interest from such a large group of  
25 investors, the final pricing/spread is determined through the aggregation of  
26 multiple independent investor perspectives, rather than relying solely on any  
27 one investor's expectation for pricing. As demonstrated in part a), OPG's recent  
28 bond issuances (and indicative new issue spreads) have consistently  
29 outperformed the Bloomberg BBB-rated utilities index of which it is a  
30 constituent.  
31

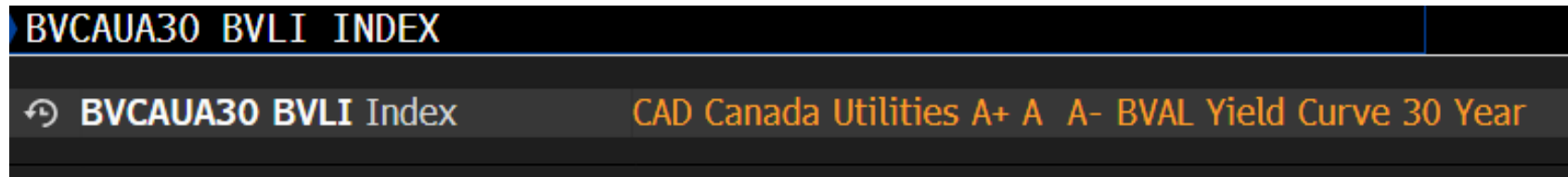
32 In executing on the above, OPG leverages internal treasury expertise and support  
33 from leading banking institutions to help ensure a cost-effective and risk-managed  
34 funding program amidst OPG's increasing borrowing requirements. OPG's treasury  
35 department comprises staff with extensive capital markets and treasury experience,  
36 while its ongoing external relationships include major Canadian and international  
37 investment banks that are able to provide ongoing insight into debt markets and  
38 advise on issuance strategy. This combination of internal and market experience,  
39 together with the extensive treasury planning processes, allows OPG to manage  
40 its debt program in an efficient and economical way.

**Attachment 1 – Bloomberg Utilities Indices Constituent Bonds**

Steps to access the BVCAUA30 Index and BVCAUA3M Index constituent bonds are as follows:

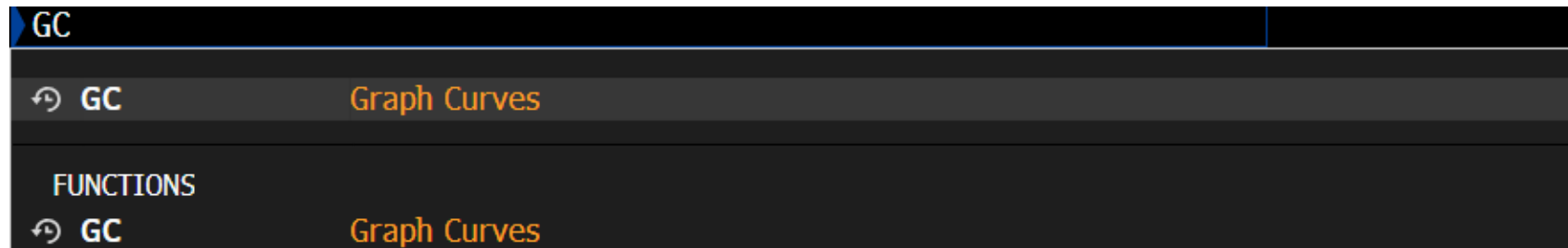
1. In a new Bloomberg tab, key in either BVCAUA30 BVLI Index or BVCAUA3M BVLI Index in the command line at the top of the screen and press Enter (Figure 1).

**Figure 1 – BVCAUA30 or BVCAUA3M Search on Bloomberg**



2. Once the security has loaded, key in “GC” in the command line and press Enter to graph the yield curve across all tenors of the term structure (Figure 2).

**Figure 2 – Graph Curves on Bloomberg**



3. The term structure of yields for the Bloomberg A-rated utilities index will be displayed (Figure 3).

1  
2  
3

Figure 3 – Bloomberg A-Rated Utilities Index Yields Graph

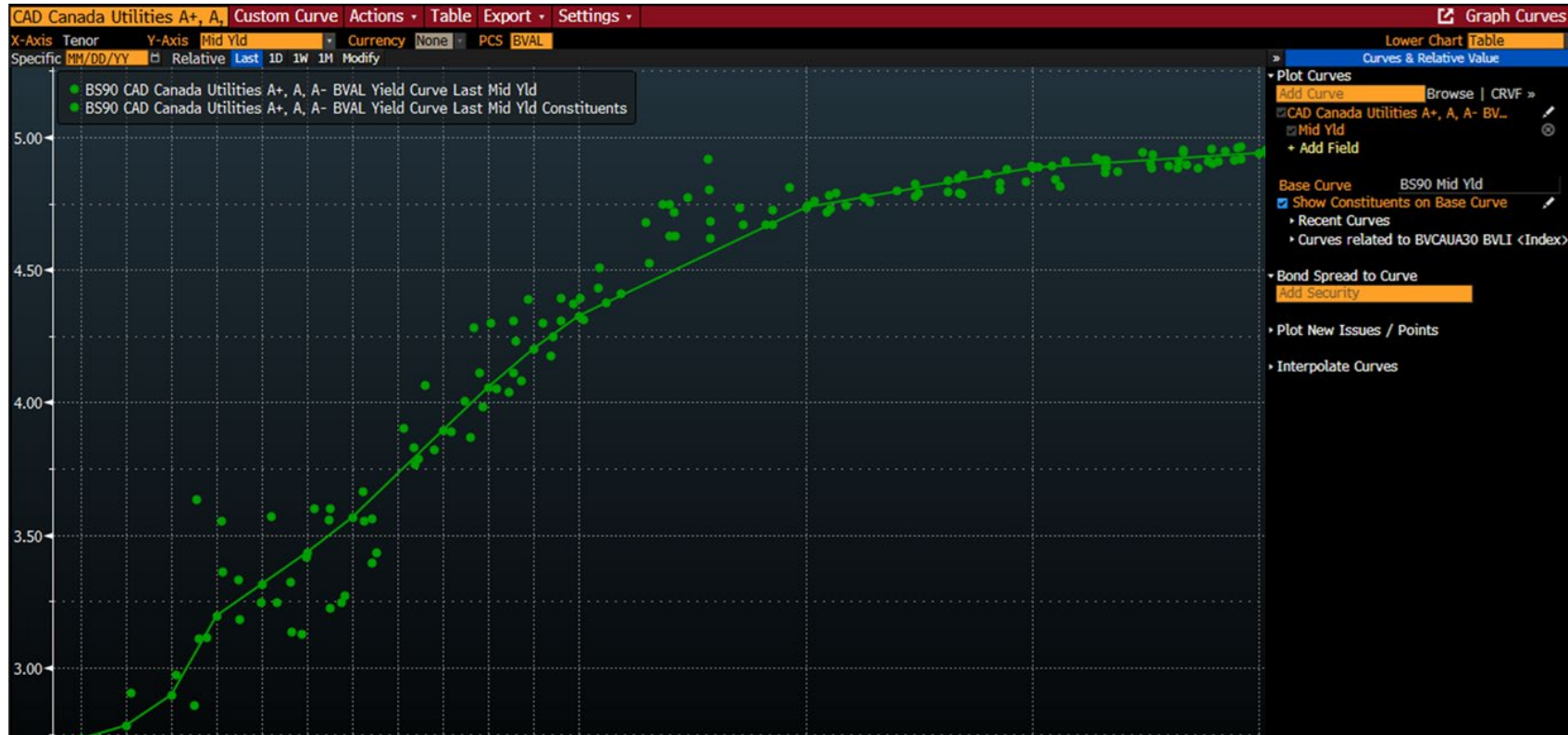


4  
5  
6  
7  
8  
9

4. In the toolbar on the right side, check the “Show Constituents on Base Curve” on the right-sided toolbar to view the constituent bonds graphically. In Figure 4, the green dots plotted on the graph represents the individual bonds and their respective yields that comprise the index.

Witness Panel: Finance, D&V, Cost of Capital, and Customer Impacts

Figure 4 – Bloomberg A-Rated Utilities Index Constituent Bonds Graph



5. Click the “Table” button in the red bar at the top of the screen (Figure 4) to view the individual bonds in a tabular format (Figure 5). The bonds should appear in chronological order, sorted by remaining term to maturity. Click the “Export” button in the red bar to export this table to Microsoft Excel, which with Bloomberg’s excel functionality, can retrieve further information on these bonds, including full issuer name and issuance date.

Figure 5 – Bloomberg A-Rated Utilities Index Constituent Bonds Table

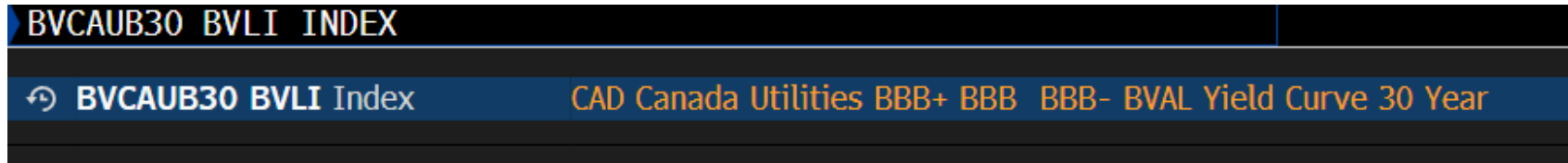
CUSIP	Maturity	Sector	Rating	Yield
11) QZ125247	.307	Utilities	A-	ENBGAS 2 3/8 08/05/26
12) LW401682	.361	Utilities	A	TORHYD 2.52 08/25/26
13) CP506670	.539	Utilities	A-	ENBGAS 7.6 10/29/26
14) AN557934	1.087	Utilities	A-	ALCTRA 2.488 05/17/27
15) Z0650234	1.500	Utilities	A-	HYDONE 1.41 10/15/27
16) CC001800	1.552	Utilities	A-	ENBGAS 6.65 11/03/27
17) AQ121564	1.604	Utilities	A	ENBGAS 2.88 11/22/27
18) BZ932766	1.785	Utilities	A	HYDONE 4.91 01/27/28
19) CP505902	2.094	Utilities	A-	ENBGAS 6.1 05/19/28
20) EH379383	2.114	Utilities	A	CUCN 5.563 05/26/28
21) ZH311435	2.478	Utilities	A-	ENBGAS 5.46 10/06/28
22) ZH423270	2.494	Utilities	A	TORHYD 5.13 10/12/28
23) ZS013782	2.973	Utilities	A	HYDONE 3.02 04/05/29
24) EC150583	3.203	Utilities	A-	EPCOR 6.8 06/28/29
25) EC150891	3.203	Utilities	A-	EPCOR 6.8 06/28/29
26) ZR033047	3.318	Utilities	A-	ENBGAS 2.37 08/09/29
27) ZM644604	3.628	Utilities	A	HYDONE 3.93 11/30/29
28) ZQ416932	3.658	Utilities	A	TORHYD 2.43 12/11/29
29) BG293867	3.874	Utilities	A	HYDONE 2.16 02/28/30
30) BH460145	3.962	Utilities	A-	ENBGAS 2.9 04/01/30
31) EC261130	4.134	Utilities	A	HYDONE 7.35 06/03/30
32) YK454642	4.463	Utilities	A-	EPCOR 3.373 10/01/30
33) Z0736839	4.501	Utilities	A	TORHYD 1 1/2 10/15/30
34) YJ174928	4.504	Utilities	A-	FTSCN 3.38 10/16/30
35) Z0807515	4.756	Utilities	A	HYDONE 1.69 01/16/31
36) B0002261	4.827	Utilities	A-	ALCTRA 1.751 02/11/31
37) BQ097416	5.207	Utilities	A-	EPCOR 2.411 06/30/31
38) BP057172	5.257	Utilities	A-	FTSCN 2.42 07/18/31

Steps to access the BVCAUB30 Index and BVCAUB3M Index constituent bonds are as follows:

1. In a new Bloomberg tab, key in either BVCAUB30 BVLI Index or BVCAUB3M BVLI Index in the command line at the top of the screen and press Enter (Figure 6).

Figure 6 – BVCAUB30 or BVCAUB3M Search on Bloomberg

1



2

3

4

2. Once the security has loaded, key in "GC" in the command line and press Enter to graph the yield curve across all tenors of the term structure (Figure 7).

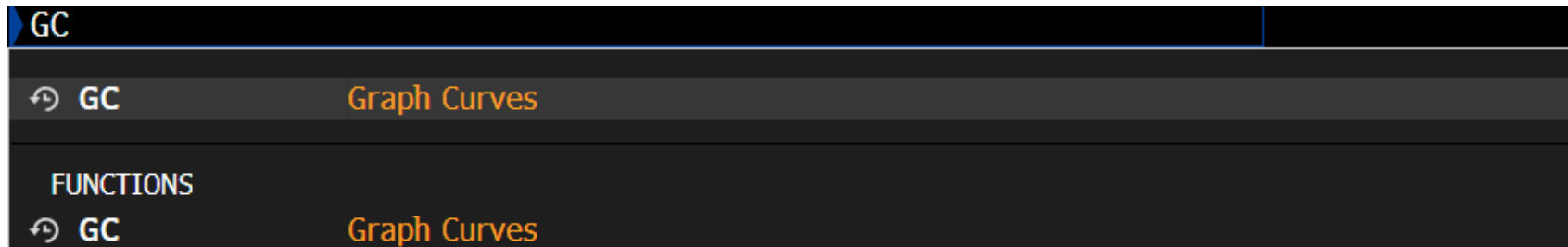
5

6

7

**Figure 7 – Graph Curves on Bloomberg**

8



9

10

11

3. The term structure of yields for the Bloomberg BBB-rated utilities index will be displayed (Figure 8).

12

13

**Figure 8 – Bloomberg BBB-Rated Utilities Index Yields Graph**

14



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 4  
 5  
 6  
 7  
 8

4. In the toolbar on the right side, check the “Show Constituents on Base Curve” on the right-sided toolbar to view the constituent bonds graphically. In Figure 9, the green dots plotted on the graph represents the individual bonds and their respective yields that comprise the index.

**Figure 9 – Bloomberg BBB-Rated Utilities Index Constituent Bonds Graph**

Witness Panel: Finance, D&V, Cost of Capital, and Customer Impacts



- 1
  - 2
  - 3
5. Click the “Table” button in the red bar at the top of the screen (Figure 9) to view the individual bonds in a tabular format (Figure 10). The bonds should appear in chronological order, sorted by remaining term to maturity. Click

Witness Panel: Finance, D&V, Cost of Capital, and Customer Impacts

1 the "Export" button in the red bar to export this table to Microsoft Excel, which with Bloomberg's excel functionality,  
 2 can retrieve further information on these bonds, including full issuer name and issuance date.  
 3  
 4

5 **Figure 10 – Bloomberg BBB-Rated Utilities Index Constituent Bonds Table**

CUSIP	Maturity	Sector	Rating	Yield Curve
11) Z0961711	.019	Utilities	BBB+	04/15/26 (103)
12) QZ198398	.753	Utilities	BBB+	ONTPOW 1.17 04/22/26
13) ZG438535	.780	Utilities	BBB-	BAMREP 3.63 01/15/27
14) B0549956	.917	Utilities	BBB-	CPXCN 5.378 01/25/27
15) BH577637	.977	Utilities	BBB+	ALACN 2.166 03/16/27
16) AP357167	1.470	Utilities	BBB+	ACICN 3.13 04/07/27
17) AP391526	1.470	Utilities	BBB-	ONTPOW 3.315 10/04/...
18) DA156758	1.572	Utilities	BBB-	ALACN 3.98 10/04/27
19) ZN296856	1.582	Utilities	BBB+	ALACN 3.025 11/10/27
20) ZL753372	1.684	Utilities	BBB	BIP 5.616 11/14/27
21) BP514537	2.084	Utilities	BBB+	BRUPOW 4.7 12/21/27
22) BM766123	2.125	Utilities	BBB-	FTSCN 2.18 05/15/28
23) AS901820	2.141	Utilities	BBB	ALACN 2.075 05/30/28
24) AU429346	2.409	Utilities	BBB+	ENMAXC 3.836 06/05/28
25) ZI877043	2.420	Utilities	BBB-	BIP 4.193 09/11/28
26) AW011527	2.642	Utilities	BBB+	CPXCN 5.816 09/15/28
27) BS561107	2.686	Utilities	BBB	ACICN 4.26 12/05/28
28) ZF133431	2.735	Utilities	BBB-	BRUPOW 2.68 12/21/28
29) AU586133	2.754	Utilities	BBB+	ALACN 4.672 01/08/29
30) BW614218	3.127	Utilities	BBB+	BAMREP 4 1/4 01/15/29
31) AM476184	3.184	Utilities	BBB	FTSCN 4.431 05/31/29
32) ZR583251	3.414	Utilities	BBB+	BRUPOW 4.01 06/21/29
33) ZR959977	3.485	Utilities	BBB+	ONTPOW 2.977 09/13/...
34) ZQ139681	3.510	Utilities	BBB	BIP 3.41 10/09/29
35) ZM341731	3.743	Utilities	BBB+	ENMAXC 3.876 10/18/29
36) ZR589534	3.754	Utilities	BBB+	ACICN 5.02 01/11/30
37) ZQ475788	3.819	Utilities	BBB-	BAMREP 3.38 01/15/30
38) BH550431	3.981	Utilities	BBB+	CPXCN 4.424 02/08/30
				ONTPOW 3.215 04/08/...

6

**Board Staff Interrogatory #029**

**Interrogatory**

**Reference:**

**Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / pp. 1, 5-7**

**Preamble:**

OPG stated that it has made updates to the methodology used to determine the cost of planned long-term debt issues in this application, compared to previous proceedings.

OPG noted that previously IHS Markit's Global Insight Economics (Global Insight) was used as a third-party market source for forecast Government of Canada (GoC) bond rates.

OPG also noted that there is an increased volume of planned debt issues, as well as observed notable divergence in forecast data between Global Insight and other economist views. Over the 2025-2031 period, OPG forecasts issuing approximately \$10 billion in long-term debt that is wholly or partially attributed to its regulated operations and which will support the planned capital investments. OPG stated that this does not include the forecast long-term debt issues attributed to OPG's anticipated cash contributions to DNNP LP, beginning in 2026.

OPG stated that the forecast in this proceeding has been determined using an equally weighted combination of 10-year and 30-year durations.

OPG stated that Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy.

**Question(s):**

- a) Please explain why there is an "Increased volume of planned debt issues", other than supporting planned capital investments.
- b) Please explain how OPG concluded it was appropriate to use "an equally weighted combination of 10-year and 30-year durations" to determine its forecast, rather than other proportions.

- 1 c) Please explain why OPG is stating in the current application that there was an  
2 “observed notable divergence in forecast data between Global Insight and other  
3 economist views” and not in prior proceedings.  
4  
5 d) Please explain whether OPG attempted to use different methodologies to develop  
6 long-term debt costs and short-term debt costs, other than using Bloomberg  
7 forecasts, given OPG’s statement that “Bloomberg forecasts currently do not  
8 extend beyond 2028 since many economists are not publishing forecasts beyond  
9 two years given the current uncertainty in the global economy.”  
10  
11

12 **Response**  
13

- 14 a) The increased volume of planned debt issues referenced is due to OPG’s increased  
15 funding requirements, driven by planned capital investments in the regulated  
16 assets.  
17  
18 b) OPG determined that it is appropriate to use an equally weighted combination of  
19 10-year and 30-year durations to determine the forecast cost of long-term debt  
20 because, as stated at Ex. C2-1-1, p. 5, lines 3-5, such assumption is “consistent  
21 with the transaction OPG undertakes through its Medium-Term Notes program.”  
22 For example, since EB-2020-0290, OPG has only issued 10- and 30-year tenor  
23 bonds, with such corporate-wide and Green Bond issues shown at Ex. C1-1-2,  
24 Table 7 having a weighted average original tenor of 18 years. As noted at Ex. C1-  
25 1-2, p. 5, lines 5-7, this approach better matches the longer-term nature of the  
26 assets and reduces near-term refinancing risk, while resulting in more competitive  
27 pricing dynamics.  
28  
29 c) While OPG did not conduct a comprehensive historical review of IHS Markit’s  
30 Global Insight Economics (“Global Insight”) forecast going back to prior payment  
31 amounts proceedings, the referenced statement reflects the observations that OPG  
32 made in the course of 2024 and 2025 that, when compared to the Bloomberg Bond  
33 Yield Median Forecast (“BYFC”) and the forward rates, Global Insight’s 10-year  
34 Government of Canada (“GoC”) bond yield exhibited significant month-to-month  
35 variability when considering 1) forecasted rates within the same forecast, and 2)  
36 from one forecast to the following forecast produced in the next month. Further,  
37 OPG also noticed that historical rates in Global Insight’s forecast had started to  
38 change, when this historical data should be the actual GoC rate. These three issues  
39 are discussed further below.  
40  
41 1. **Variability within the same forecast:** OPG observed significant decreases in  
42 forecasted rates on a month-to-month basis within the same Global Insight  
43 forecast. This was prevalent for many of the forecasts generated by Global

1 Insight for 2024 and 2025. As an example, for the forecast produced in February  
 2 2025, Global Insight's 10-year GoC forecast from January to February 2025  
 3 decreased by 0.44%. Such a significant change was not observed in either the  
 4 BYFC (representing approximately a dozen economist forecasts, as discussed  
 5 below), or in the Bloomberg forward rates being predicted at that time. Notably,  
 6 OPG observed such month-to-month decreases of greater than 0.35% in seven  
 7 monthly forecasts produced by Global Insight for 2025. Chart 1 ranks the  
 8 greatest month-to-month changes within the same forecast as published for  
 9 2025 by Global Insight.

10  
 11 By comparison, the greatest change OPG observed month-to-month in the  
 12 Bloomberg forward rates produced monthly from January 2025 to February  
 13 2026 was 0.02%. Similarly, the greatest change OPG observed month-to-month  
 14 in the BYFC produced monthly from January 2025 to February 2026 were two  
 15 instances of 0.25%.<sup>1</sup>

16  
 17 **Chart 1 - Global Insight 2025 Forecasts with Month-to-Month Variability within**  
 18 **Same Forecast, where Change in Yield is >0.35%**  
 19

Month Forecast was Published	Forecast 10-Year GoC in Starting Month		Forecast 10-Year GoC in Following Month		Change in Forecasted GoC
June 2025	May 2025	3.48%	June 2025	2.36%	-1.12%
March 2025	February 2025	3.15%	March 2025	2.11%	-1.04%
April 2025	June 2025	3.60%	July 2025	2.92%	-0.68%
March 2025	March 2025	2.11%	April 2025	2.73%	0.62%
August 2025	September 2025	3.45%	October 2025	2.90%	-0.55%
June 2025	June 2025	2.36%	July 2025	2.91%	0.55%
September 2025	August 2025	3.82%	September 2025	3.33%	-0.49%
May 2025	May 2025	2.89%	June 2025	2.41%	-0.48%
May 2025	April 2025	3.36%	May 2025	2.89%	-0.47%
February 2025	January 2025	3.32%	February 2025	2.88%	-0.44%
February 2025	February 2025	2.88%	March 2025	2.45%	-0.43%
September 2025	September 2025	3.33%	October 2025	2.98%	-0.35%

20  
<sup>1</sup> Although the BYFC is published monthly, it forecasts quarterly 10-year GoC rates. Accordingly, a somewhat larger change quarter-to-quarter in their monthly forecast is to be expected compared to the forecasted monthly Bloomberg forward rates.

2. **Variability from one forecast to another:** Global Insight’s forecasts are published monthly, and there was often significant variability *between* each of the monthly forecasts that were published, beyond what was observed in either the BYFC or Bloomberg forward rates. For example, in the forecast published in July 2025, Global Insight forecasted a 10-year GoC rate of 2.86% for August 2025. In the subsequent forecast published in August 2025, Global Insight had revised their August 2025 10-year GoC forecast to 3.70%, an increase of 0.84%. Meanwhile, both sources from Bloomberg showed more muted revisions for the forecasted August 2025 10-year GoC yield of approximately 0.20%. Notably, OPG observed over 100 instances spanning eight monthly forecasts produced by Global Insight during 2025 where the change in the forecast 10-year GoC for a given month was 0.35% greater than the subsequent published Global Insight forecast for that same month. Chart 2 ranks such greatest changes in the forecast 10-Year GoC rate by Global Insight from one forecast to the next.

By comparison, for both the BYFC and Bloomberg forward rates, OPG observed no instances where the change in the forecast GoC rate for a given month was greater than 0.35% for that same month in the subsequent forecast.

**Chart 2 - Global Insight 2025 Forecasts with Variability for Same Month between Successive Forecasts, where Change in Yield is >0.35%**

Month Original Forecast Published	Month Subsequent Forecast Published	Forecast Month(s) in Question	Original Forecasted Yield	Subsequent Forecasted Yield	Change in Yield Between Forecasts
June 2025	July 2025	June 2025	2.36%	3.60%	1.24%
March 2025	April 2025	March 2025	2.11%	3.32%	1.21%
July 2025	August 2025	July 2025	2.92%	3.77%	0.85%
July 2025	August 2025	August 2025	2.86%	3.70%	0.84%
July 2025	August 2025	September 2025	2.82%	3.45%	0.63%
May 2025	June 2025	May 2025	2.89%	3.48%	0.59%
September 2025	October 2025	October 2025 - May 2027	2.65% - 2.98%	3.20% - 3.53%	20 instances >0.40%, including 9 >0.50%

November 2025	December 2025	February 2026 - October 2028	2.83% - 3.04%	3.27% - 3.48%	33 instances of 0.44%
April 2025	May 2025	April 2025	2.98%	3.36%	0.38%
March 2025	April 2025	July 2027 - February 2028	2.56% - 2.59%	2.94% - 3.00%	8 instances >0.37%
October 2025	November 2025	August 2025 - September 2028	3.19% - 3.82%	2.83% - 3.42%	36 instances >0.35%

1  
 2 **3. Changes in historical actual data within the forecast that should have**  
 3 **remained unchanged:** Global Insight publishes monthly forecasts in  
 4 spreadsheet format that includes both historical actual 10-year GoC yields and  
 5 that month's forecast of future 10-year GoC yields. The historical actual 10-year  
 6 GoC yields, however, changed in Global Insight's November 2025 publication  
 7 when, as historical actual yield data, it should have remained static. Specifically,  
 8 OPG observed that the historical GoC yields for the entire period inclusive from  
 9 January 2000 to September 2025 had changed in the forecast spreadsheet  
 10 published by Global Insight in November 2025 when compared to such  
 11 spreadsheet produced in October 2025. For example, the October 2025  
 12 spreadsheet had a historical March 2025 GoC yield of 3.32% compared to the  
 13 November 2025 spreadsheet reporting such yield at 3.01%, a decrease of  
 14 0.31%.

15  
 16 In Attachment 1, OPG has reproduced, for comparison, the full history of Global  
 17 Insight's 10-year GoC forecasts, the 10-year BYFC, and the Bloomberg 10-year  
 18 forward curves, compiled from January 2024 to March 2026. OPG observes that  
 19 the Global Insight forecasts diverged significantly from both the BYFC and the  
 20 Bloomberg forward curves over this period. For context, Attachment 1 also includes  
 21 the actual Bank of Canada 10-year GoC yield that manifested.

22  
 23 Despite OPG engaging Global Insight to understand the three issues highlighted  
 24 above, Global Insight was unable to provide a satisfactory explanation thereof to  
 25 OPG. As such, at the time of filing the Application, OPG could not adequately  
 26 explain the variability in the forecasts nor changes in historical data observed in the  
 27 Global Insight publications.

28  
 29 d) OPG considered several alternatives for forecasting the GoC rates for this  
 30 Application, in addition to the chosen method of blending the BYFC with the  
 31 Bloomberg forward rates.

1 First, OPG considered using Consensus Economics, which is another economist  
2 forecast. However, Consensus Economics does not forecast the 30-year GoC bond  
3 yield, which would not have allowed the inclusion of the 30-year tenor assumption  
4 in OPG's long-term debt forecast cost. As discussed in part (a) and part (b) above,  
5 this would have been inconsistent with OPG's actual experience and expectations  
6 and would have resulted in an inaccurate forecast.

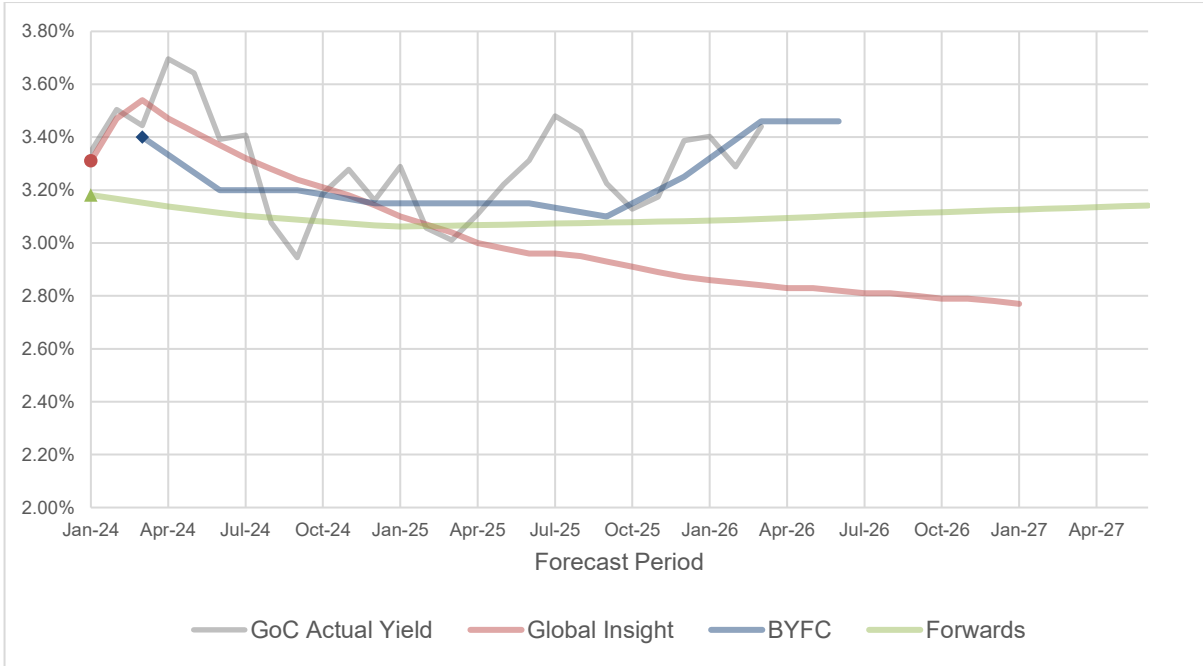
7  
8 Second, OPG considered reaching out to individual Canadian banks to obtain  
9 bespoke forecasts. However, given that the BYFC survey already sources  
10 individual forecasts from each of the same banks (and several international banks  
11 as well), and that the BYFC is readily available for viewing by any Bloomberg  
12 subscriber, OPG concluded that the simplicity and transparency of the BYFC would  
13 be superior to any bilaterally produced forecast. For example, the March 2026  
14 BYFC survey had 12 different economists being surveyed for the 10-year GoC  
15 bond yield, and nine different economists for the 30-year GoC bond yield. This  
16 would be a greater number of forecasts than OPG would reasonably be able to  
17 access on an individual basis, making the BYFC's consensus view amongst a  
18 number of forecasts superior in reducing the inherent possibility of a single  
19 forecast's bias and error. For these reasons, OPG did not pursue obtaining  
20 bespoke forecasts from individual banks.

21  
22 Lastly, OPG considered adopting the Bloomberg forward curve as the sole forecast  
23 source. The benefit of incorporating Bloomberg forward rate into the forecast is that  
24 these curves are derived mathematically from transactable rates in highly liquid and  
25 transparent spot markets, rather than econometric models, and therefore reflect  
26 more diverse views from the trading and investment community. In more  
27 unpredictable markets, particularly at times of global geopolitical uncertainty that  
28 has manifested throughout 2025 and into 2026, econometric models may be slower  
29 to respond to such events, as they are typically trained on historical information.  
30 However, while the sole use of the forward rates for forecasting purposes is a viable  
31 alternative, OPG ultimately decided that combining this source with a consensus  
32 econometric forecast represented a broader, more balanced approach, while  
33 providing some continuity with past payment amounts proceedings through the use  
34 of an econometric.

35  
36 For clarity, OPG did not consider using the DLTDR for forecasting purposes for the  
37 reasons discussed in Ex. L-C1-Staff-028.

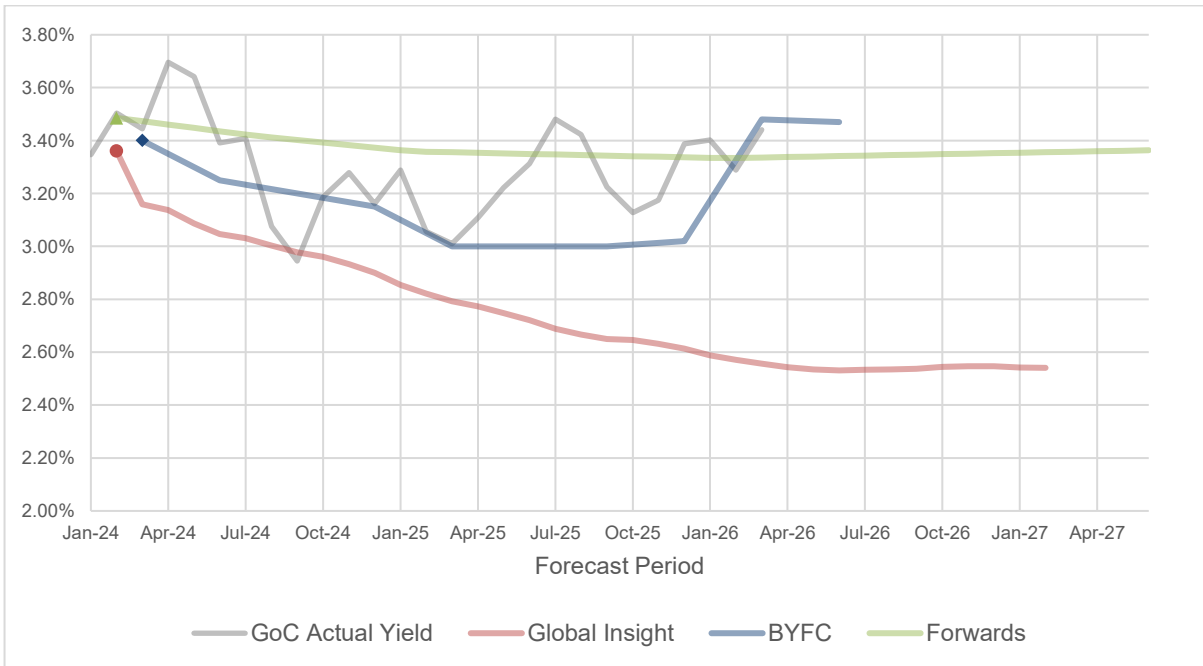
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**Figure 1: 10-Year Actual GoC and Forecasts in January 2024**



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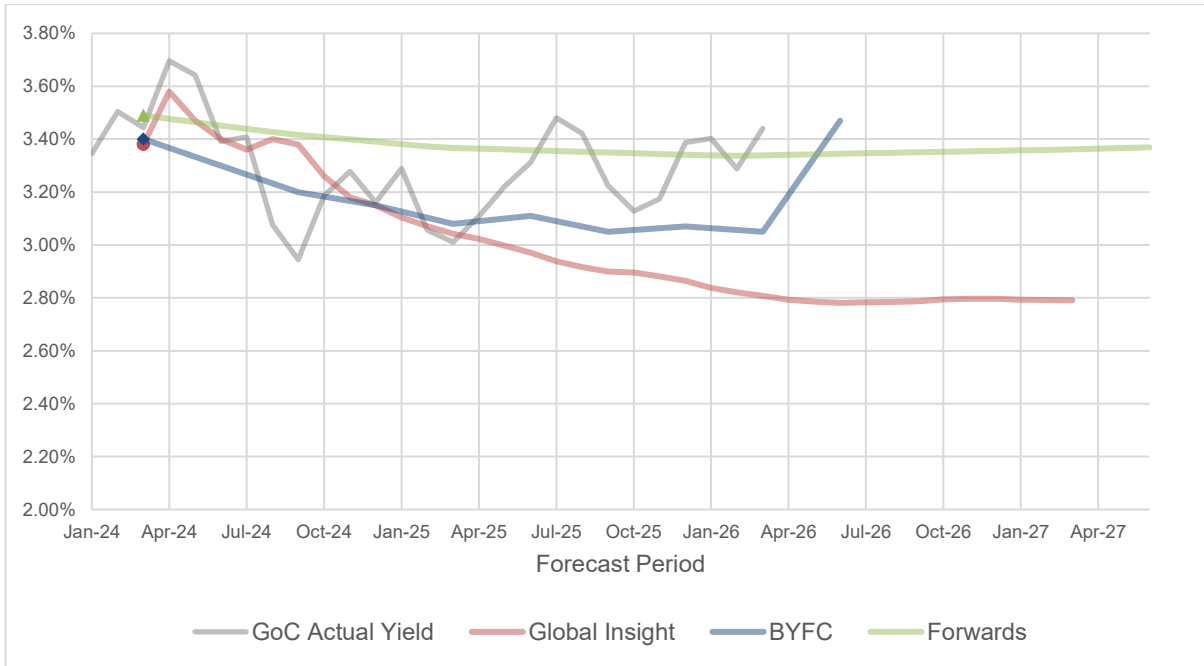
**Figure 2: 10-Year Actual GoC and Forecasts in February 2024**



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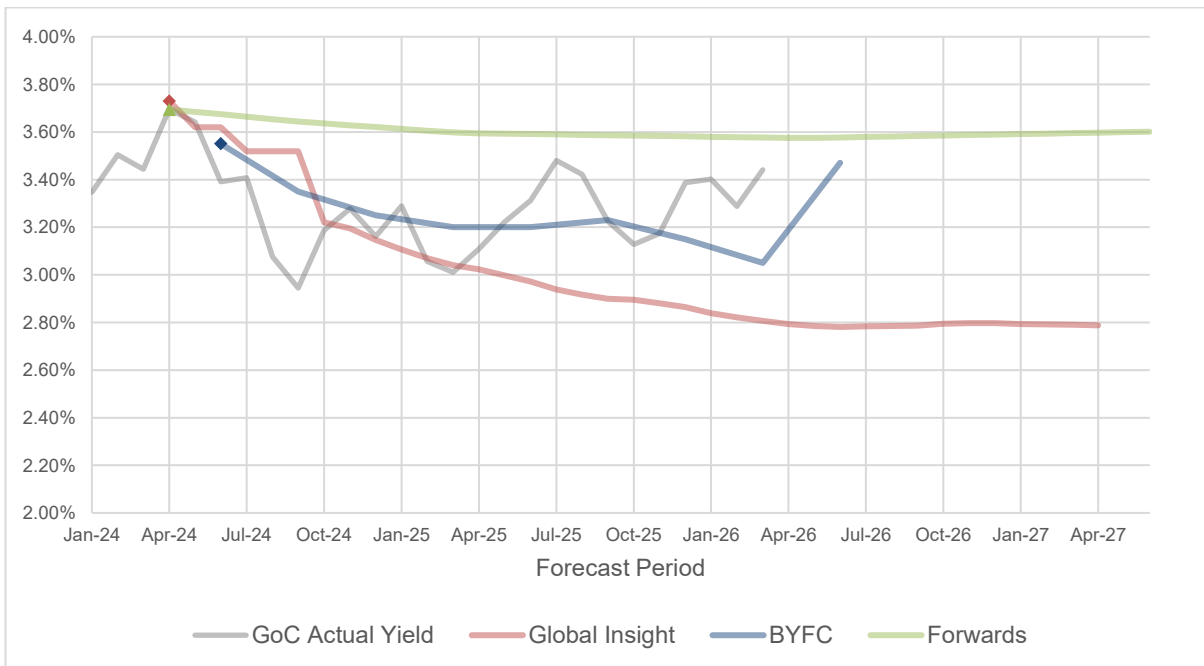
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**Figure 3: 10-Year Actual GoC and Forecasts in March 2024**



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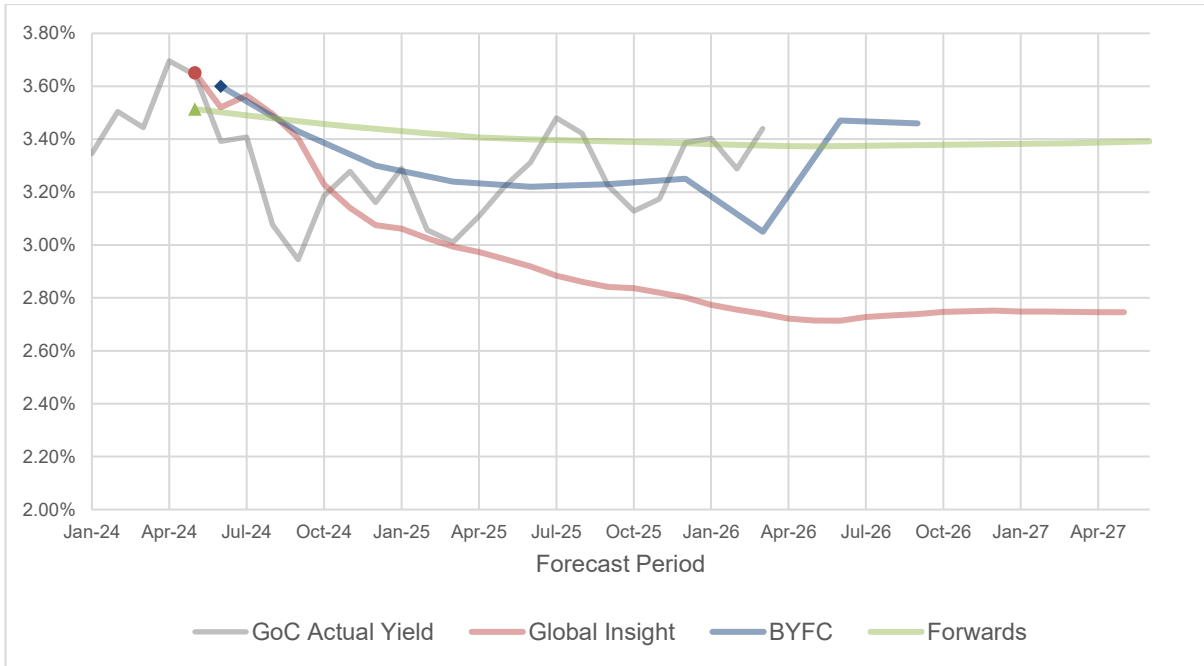
**Figure 4: 10-Year Actual GoC and Forecasts in April 2024**



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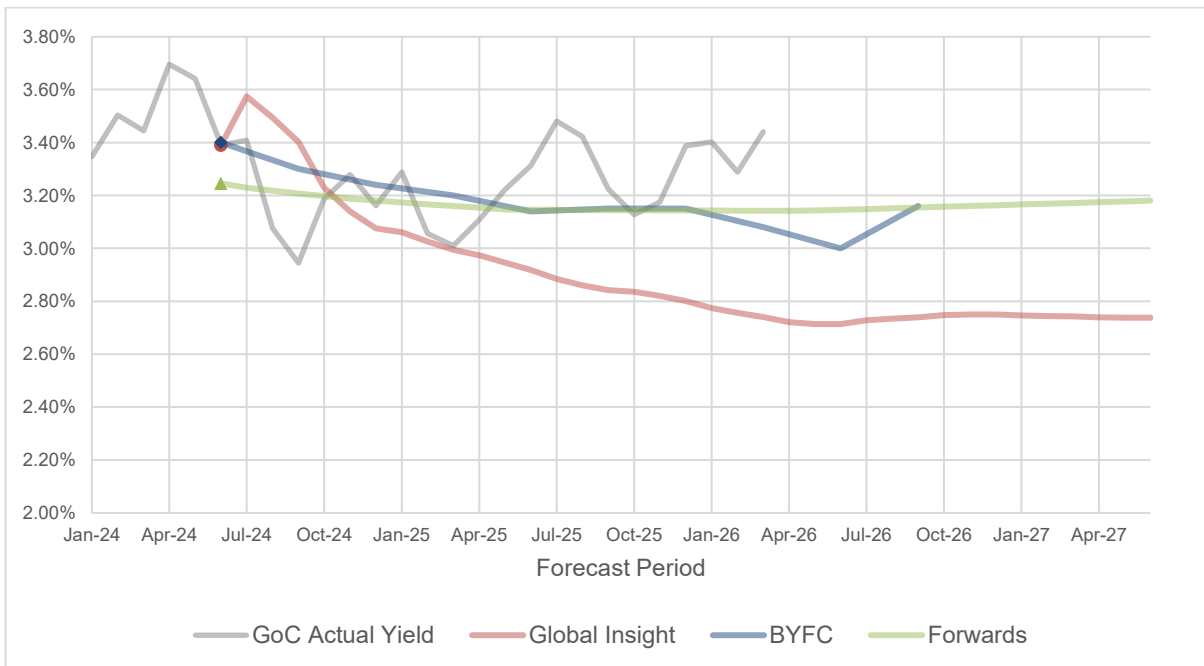
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**Figure 5: 10-Year Actual GoC and Forecasts in May 2024**



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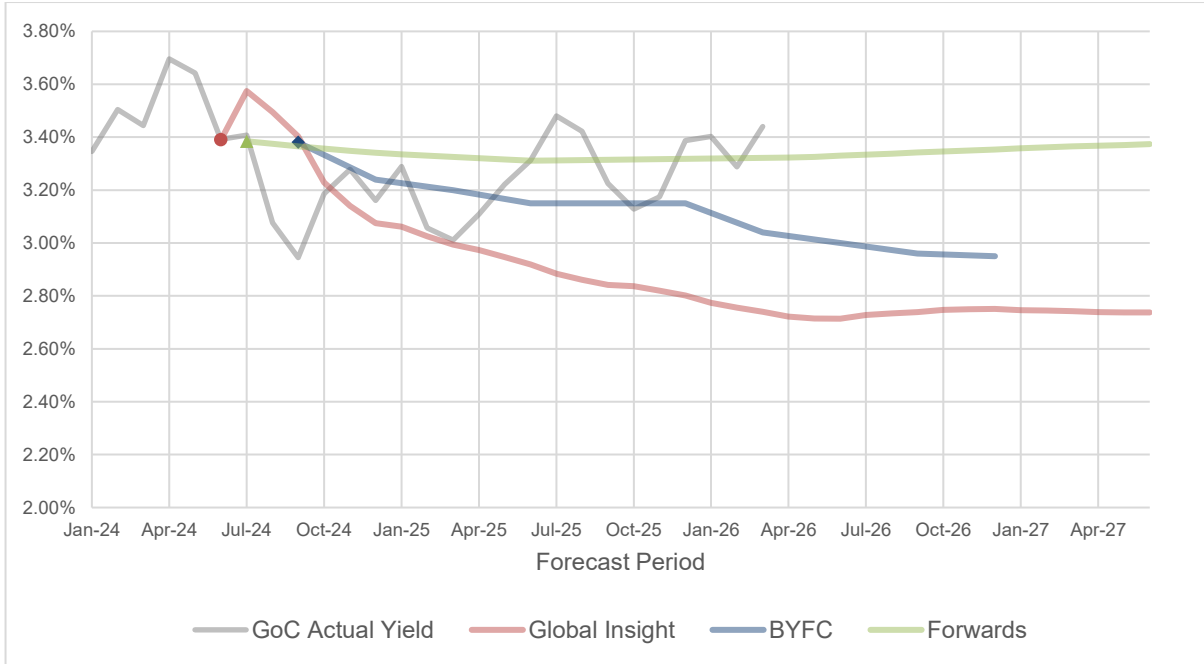
**Figure 6: 10-Year Actual GoC and Forecasts in June 2024**



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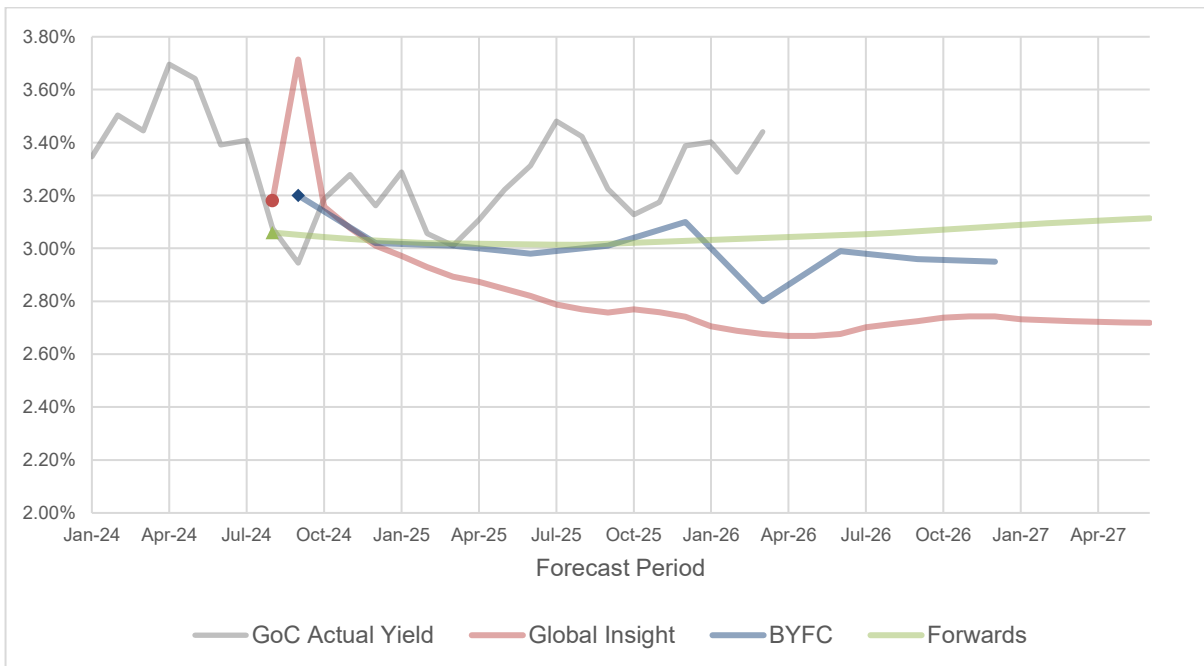
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**Figure 7: 10-Year Actual GoC and Forecasts in July 2024<sup>1</sup>**



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**Figure 8: 10-Year Actual GoC and Forecasts in August 2024**

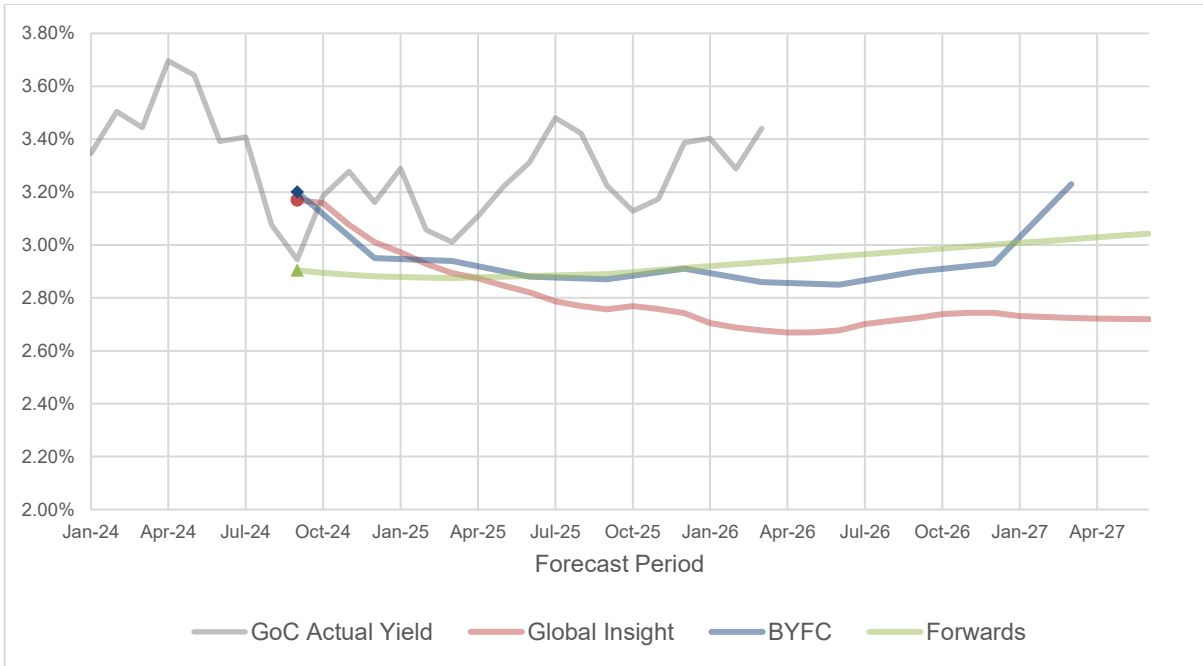


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<sup>1</sup> Global Insight's spreadsheet published in August 2024 included a 10-year GoC forecast for June 2024 instead of July 2024.

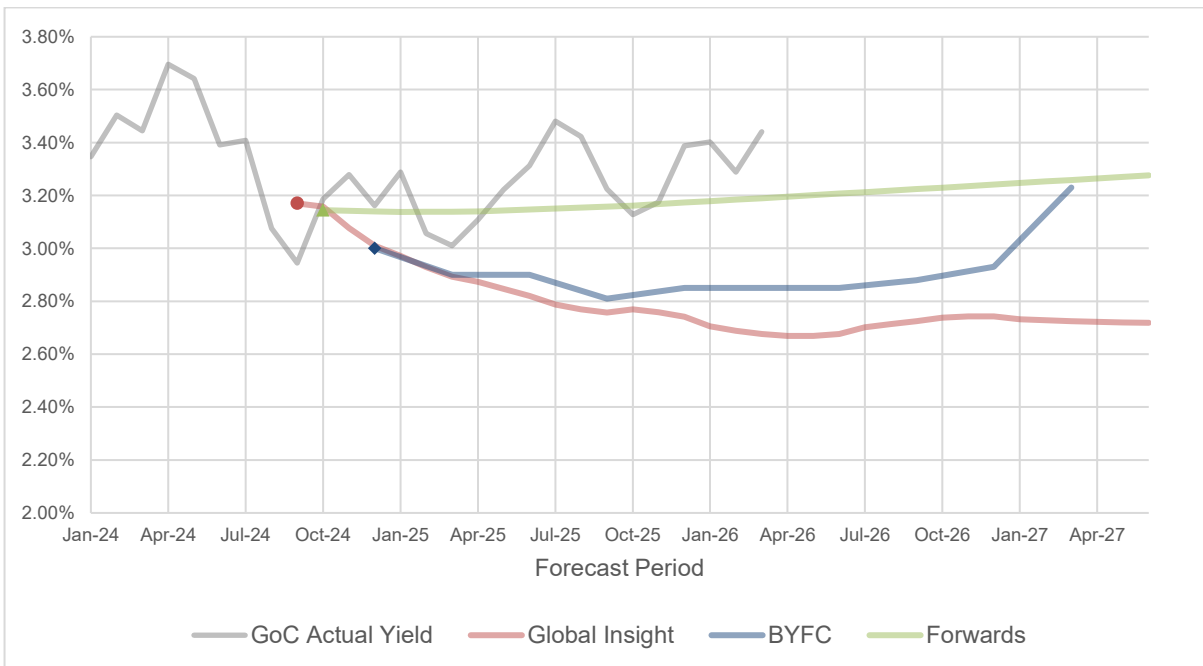
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**Figure 9: 10-Year Actual GoC and Forecasts in September 2024**



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**Figure 10: 10-Year Actual GoC and Forecasts in October 2024<sup>2</sup>**

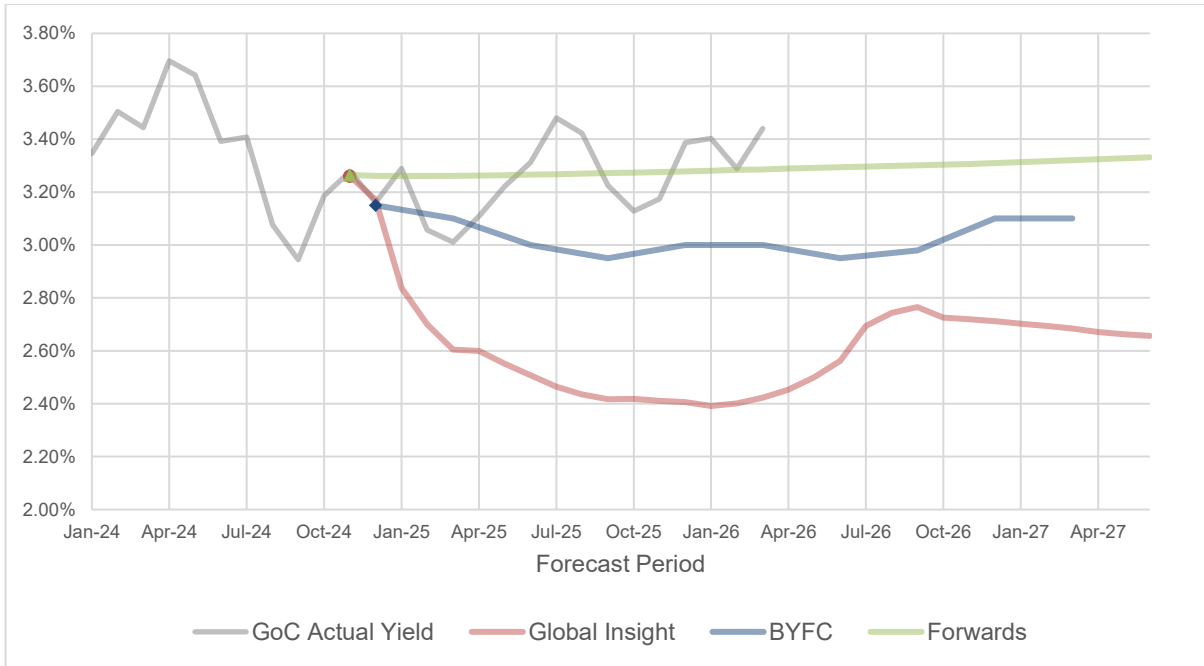


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<sup>2</sup> Global Insight's spreadsheet published in November 2024 included a 10-year GoC forecast for September 2024 instead of October 2024.

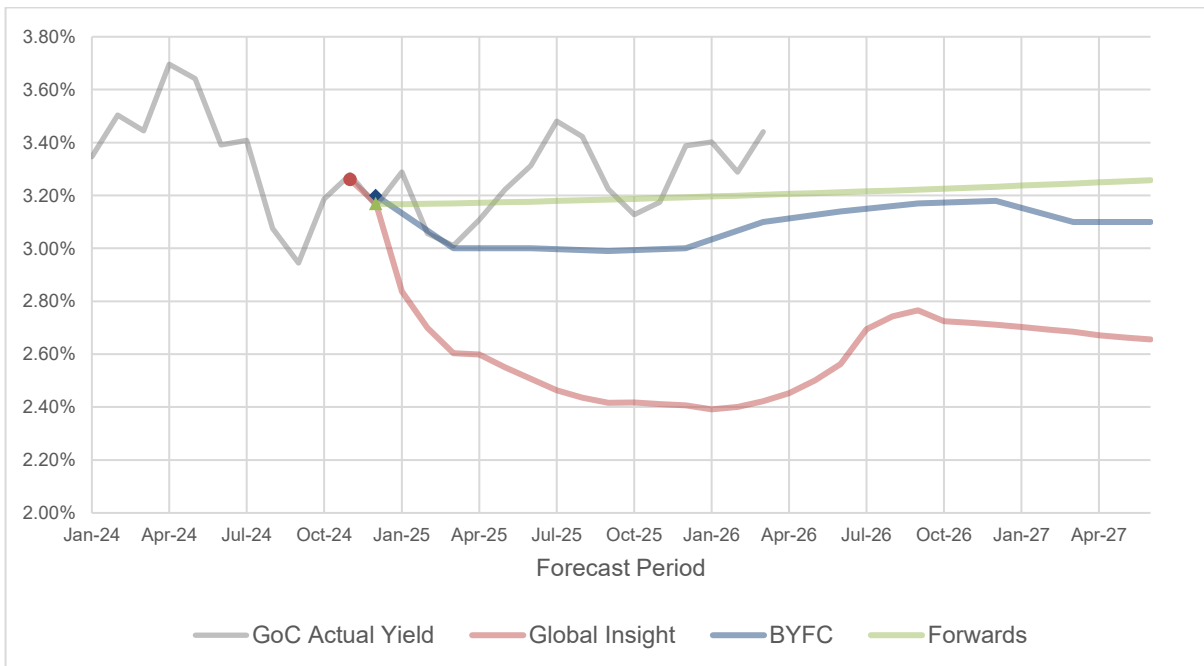
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**Figure 11: 10-Year Actual GoC and Forecasts in November 2024**



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**Figure 12: 10-Year Actual GoC and Forecasts in December 2024<sup>3</sup>**

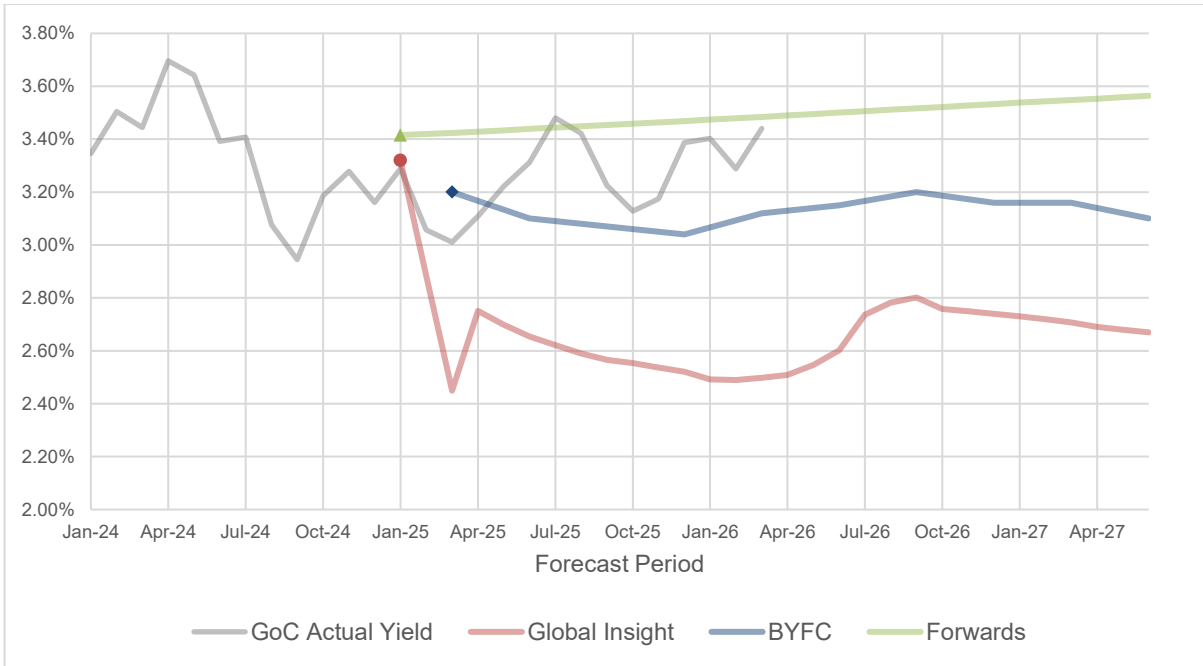


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<sup>3</sup> Global Insight's spreadsheet published in January 2025 included a 10-year GoC forecast for November 2024 instead of December 2024.

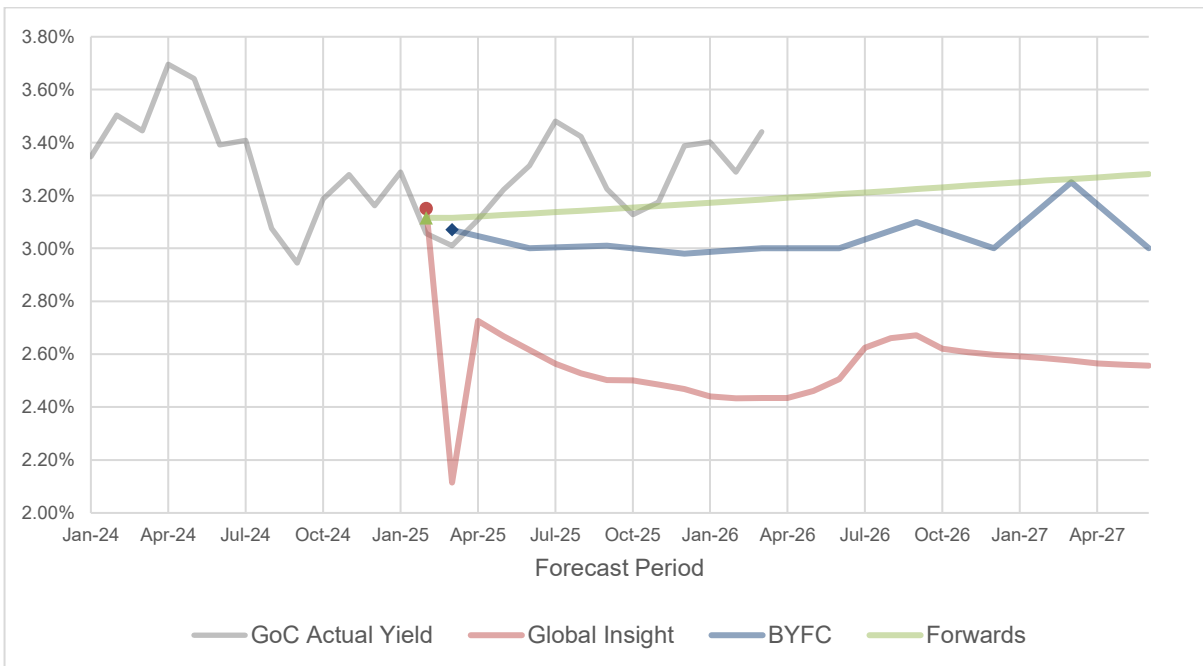
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**Figure 13: 10-Year Actual GoC and Forecasts in January 2025**



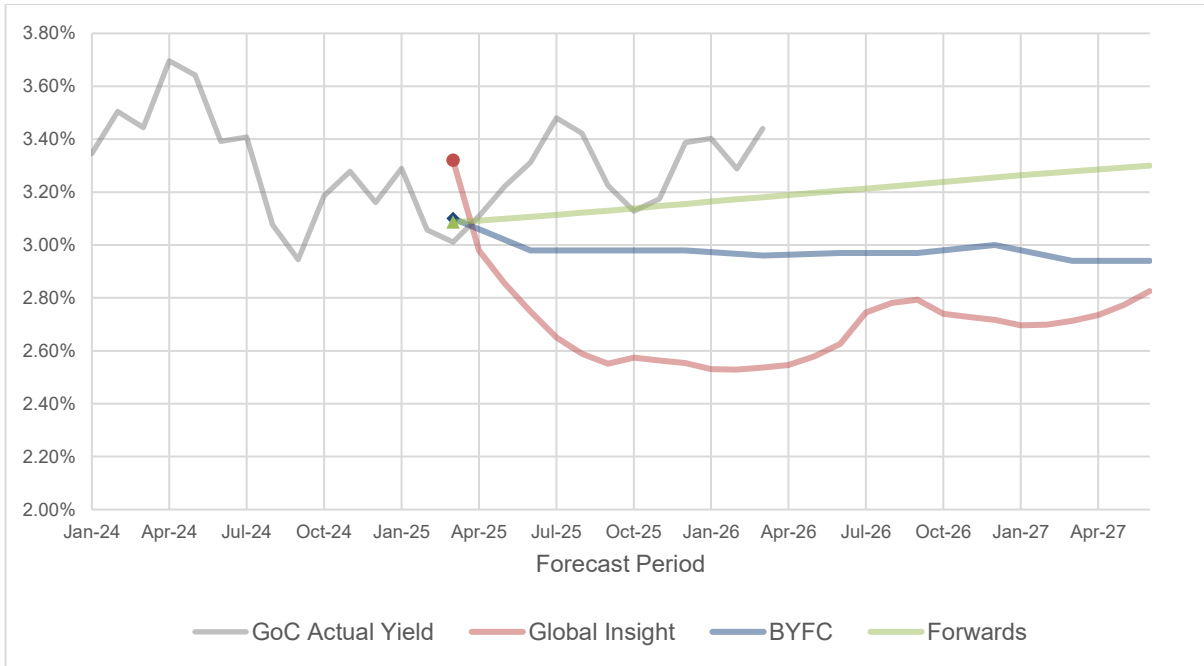
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**Figure 14: 10-Year Actual GoC and Forecasts in February 2025**

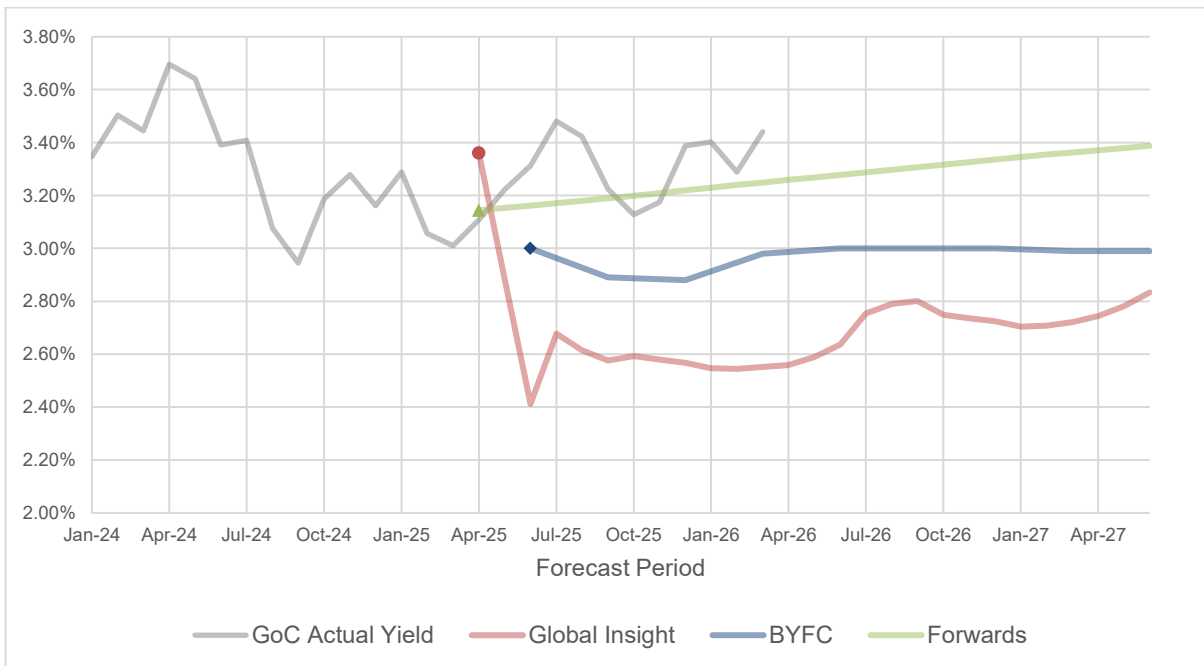


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**Figure 15: 10-Year Actual GoC and Forecasts in March 2025**

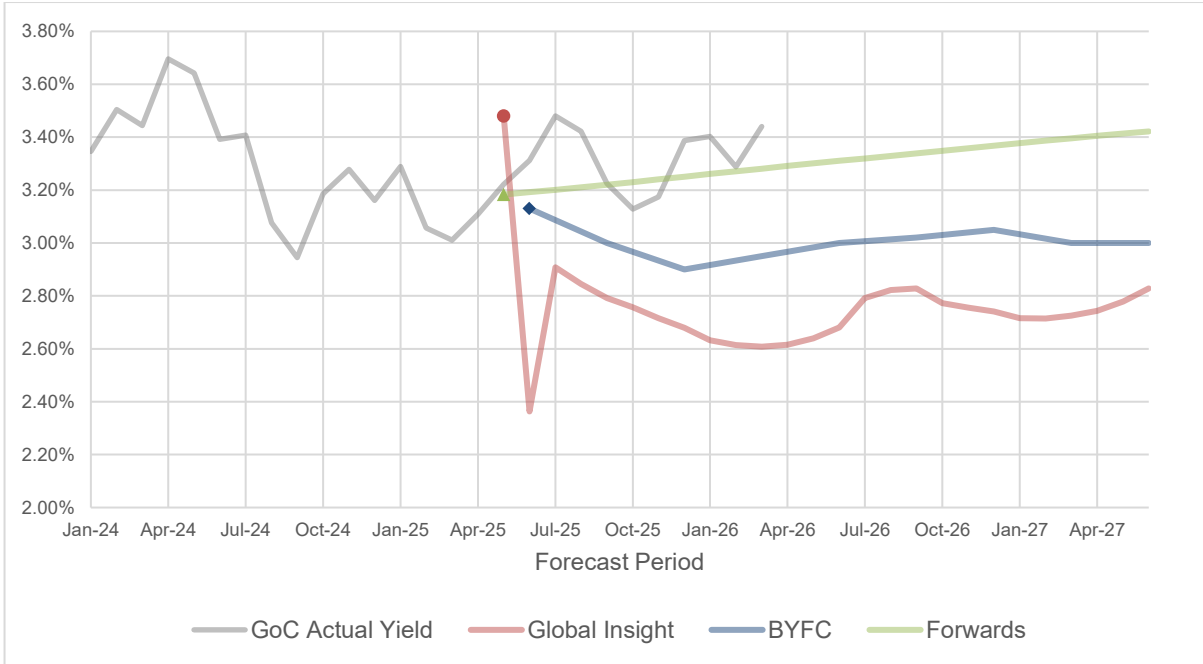


**Figure 16: 10-Year Actual GoC and Forecasts in April 2025**



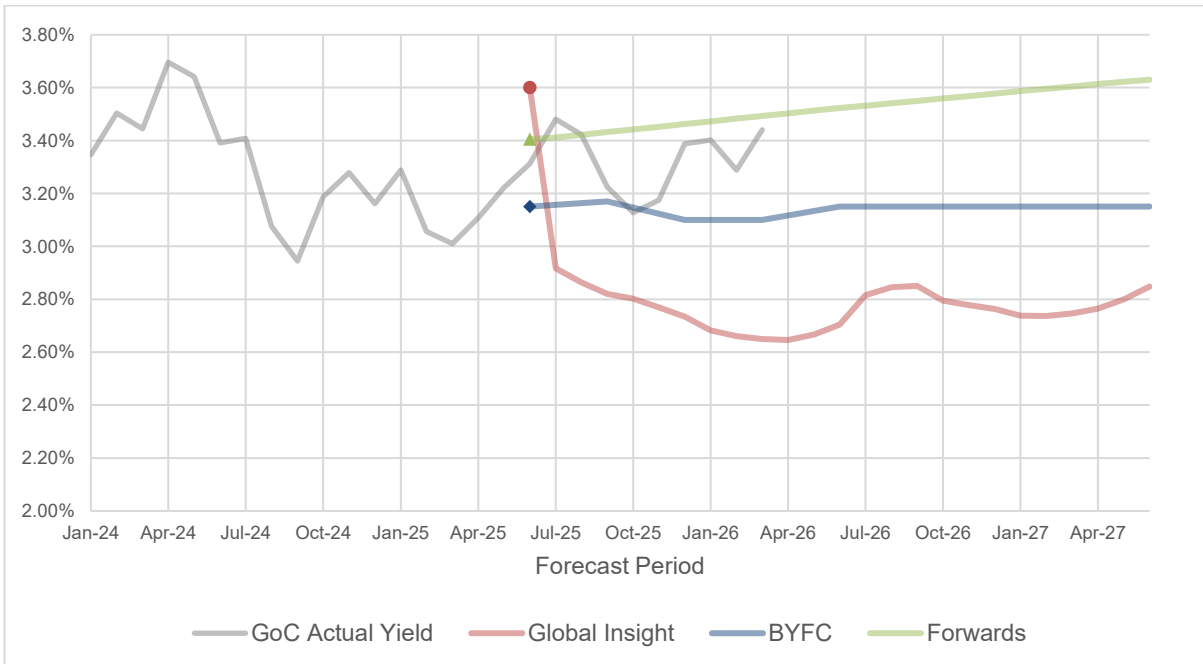
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**Figure 17: 10-Year Actual GoC and Forecasts in May 2025**



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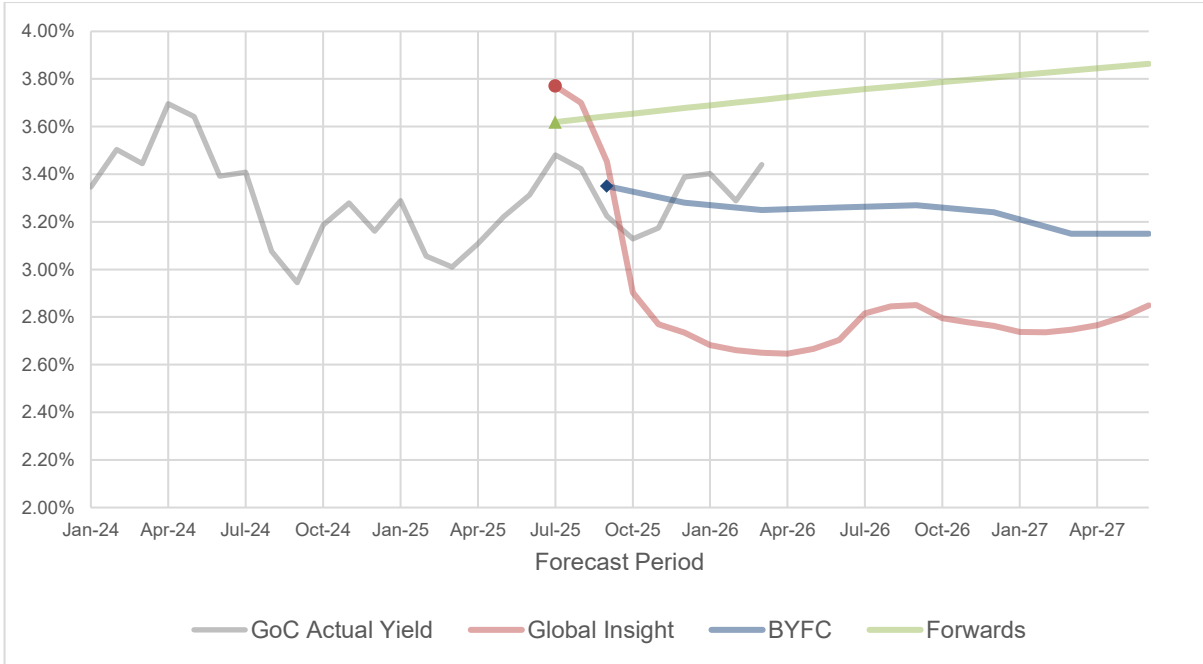
**Figure 18: 10-Year Actual GoC and Forecasts in June 2025**



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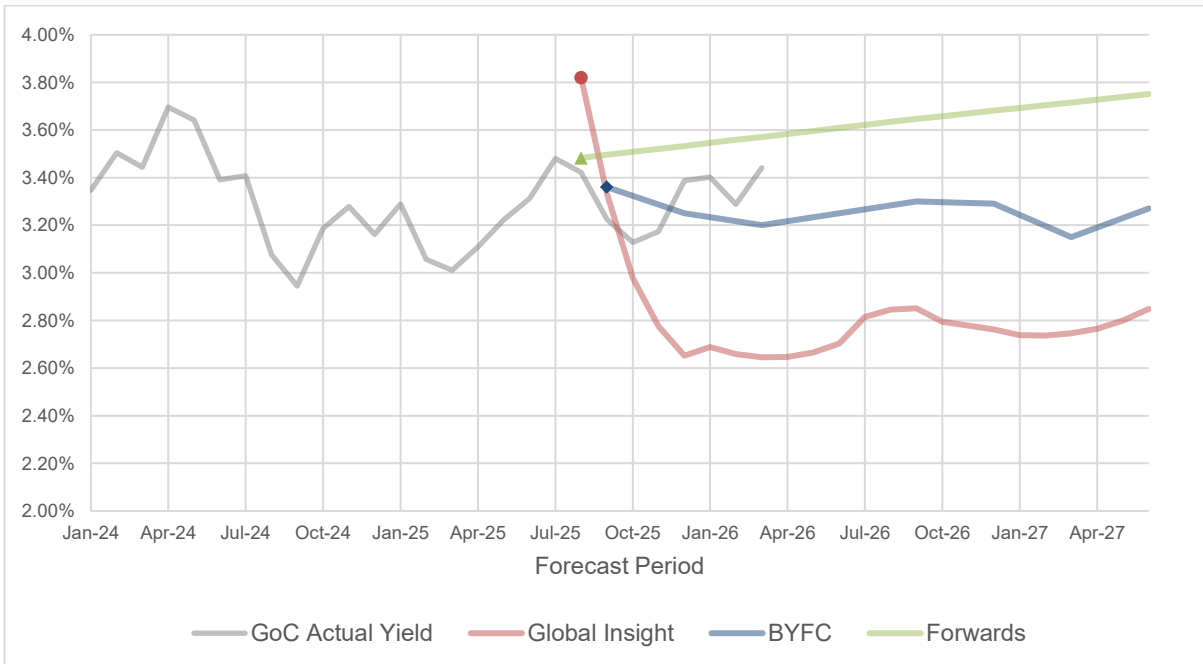
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**Figure 19: 10-Year Actual GoC and Forecasts in July 2025**



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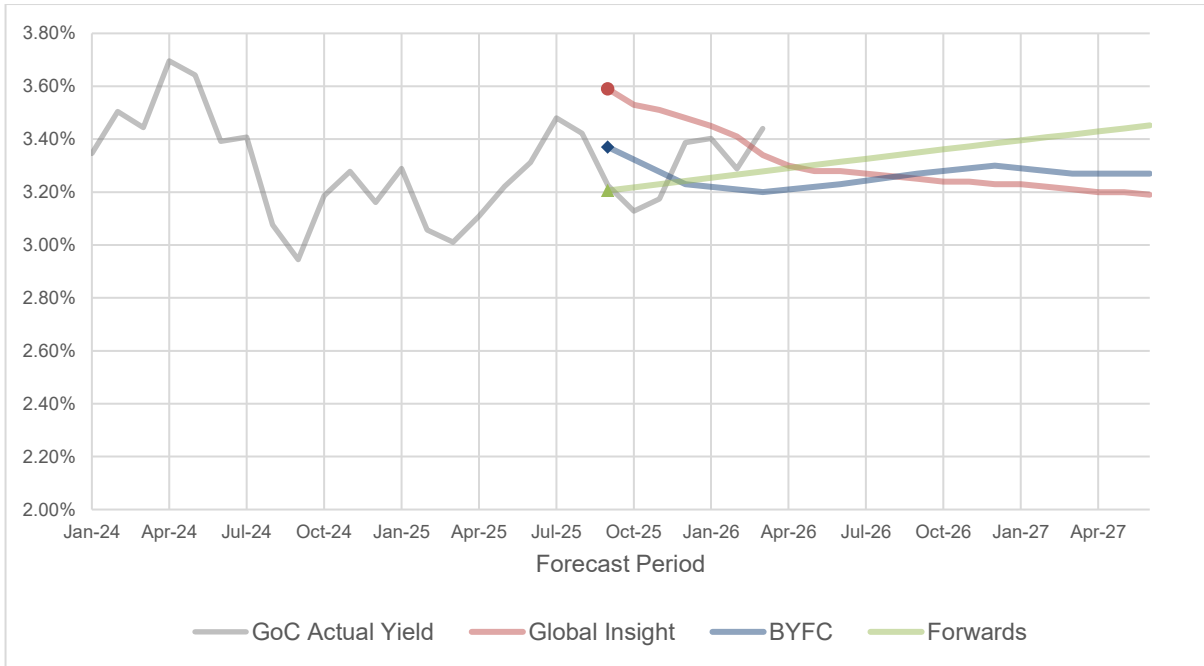
**Figure 20: 10-Year Actual GoC and Forecasts in August 2025**



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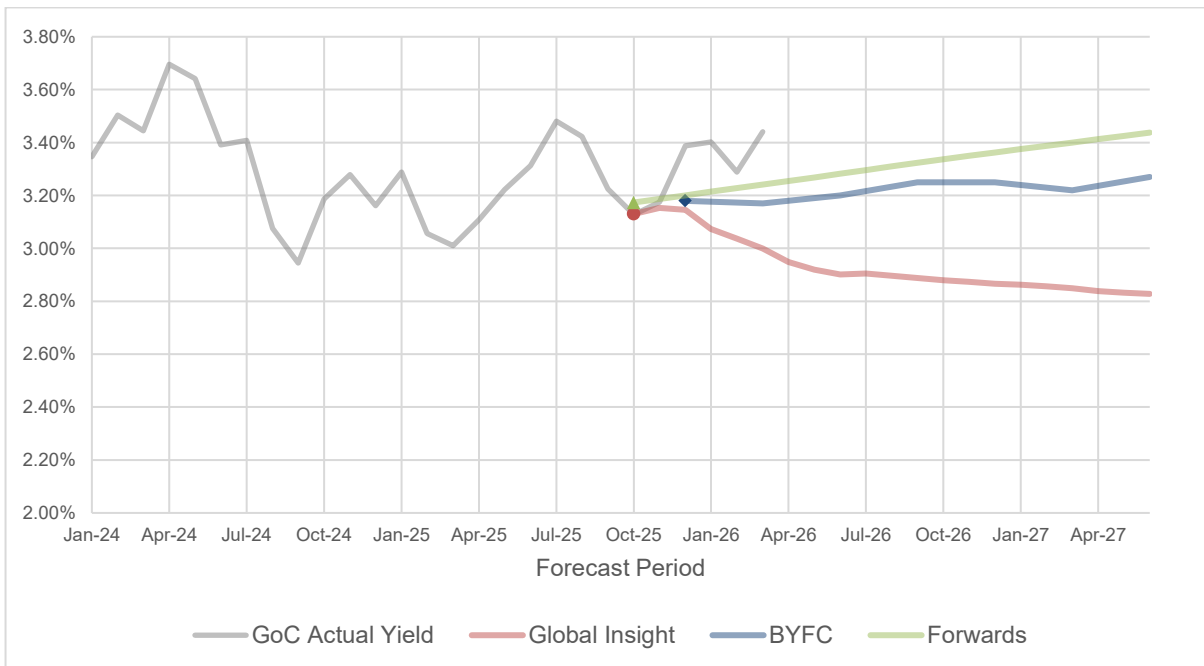
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**Figure 21: 10-Year Actual GoC and Forecasts in September 2025**



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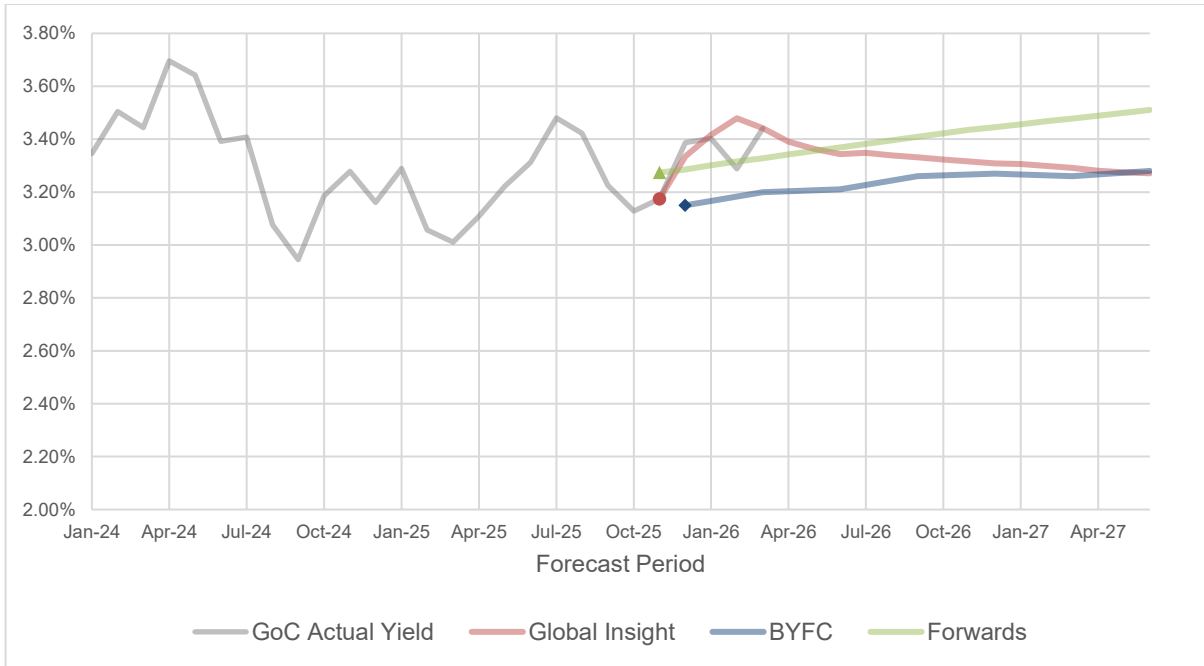
**Figure 22: 10-Year Actual GoC and Forecasts in October 2025**



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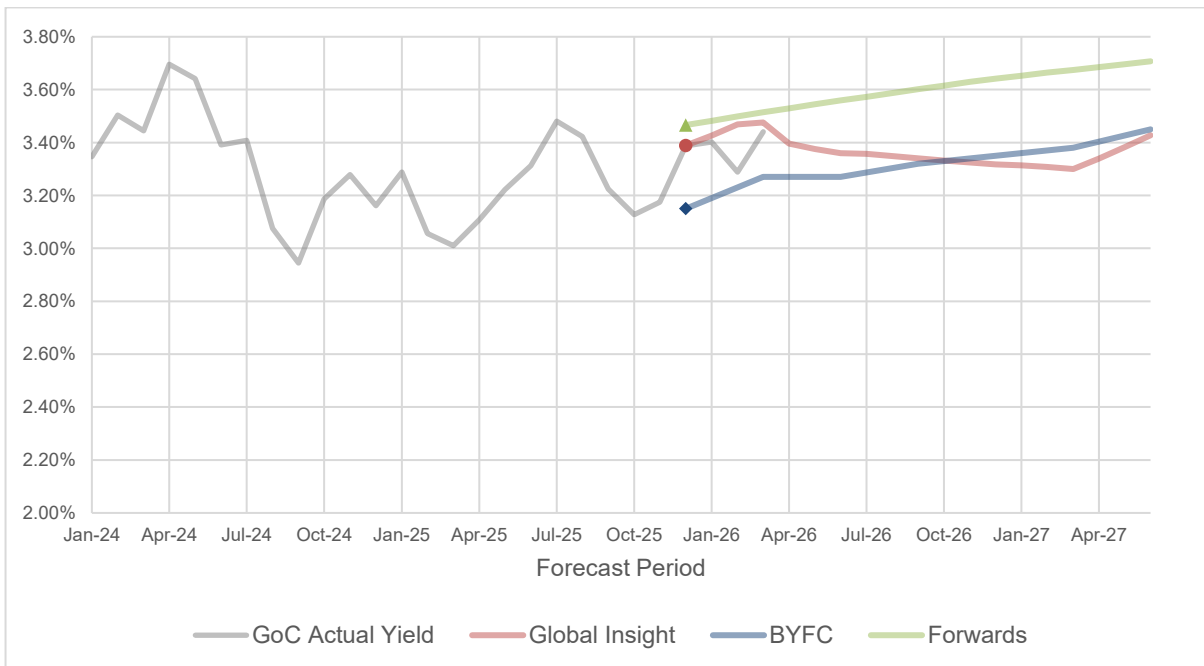
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**Figure 23: 10-Year Actual GoC and Forecasts in November 2025**



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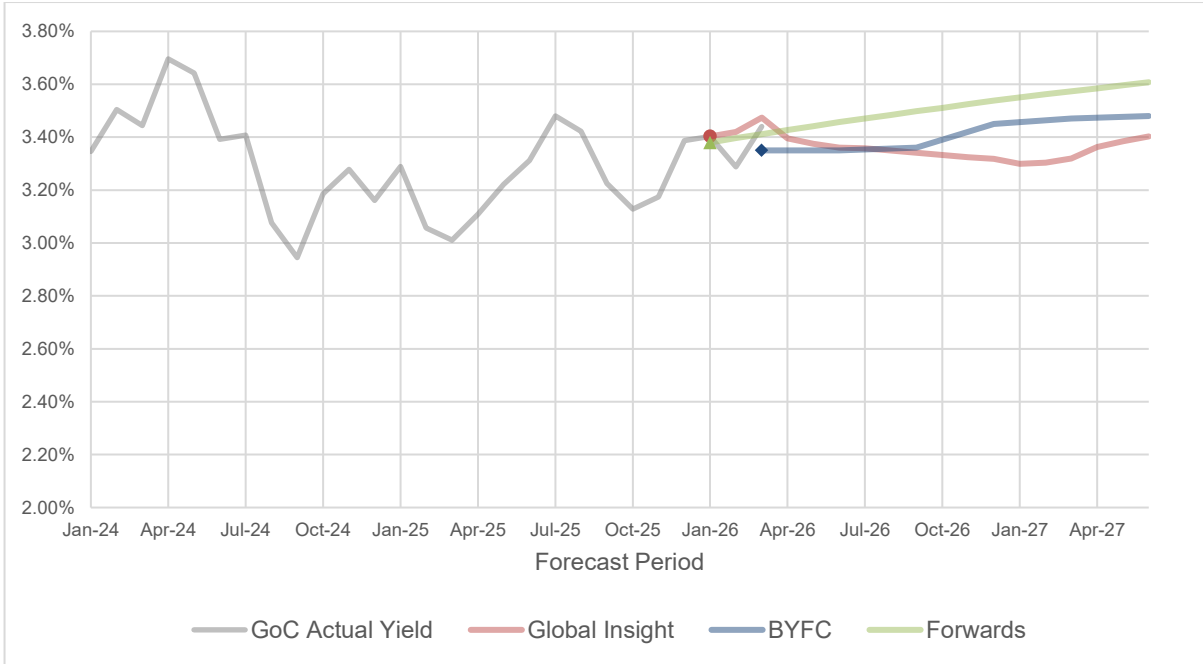
**Figure 24: 10-Year Actual GoC and Forecasts in December 2025**



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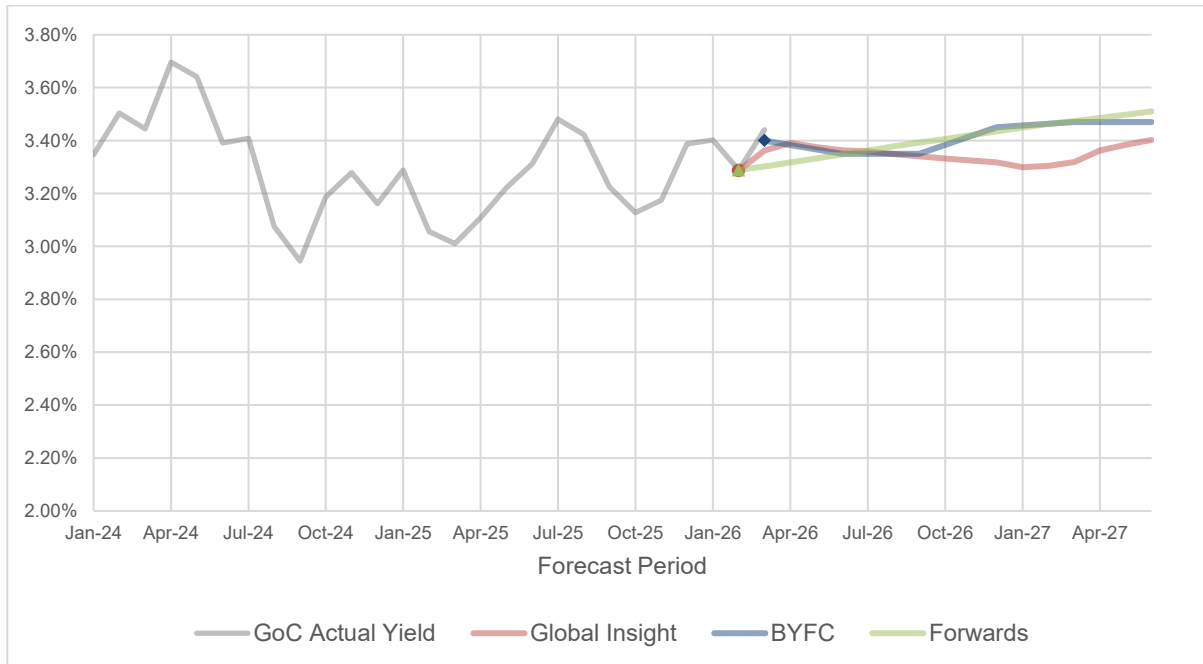
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**Figure 25: 10-Year Actual GoC and Forecasts in January 2026**



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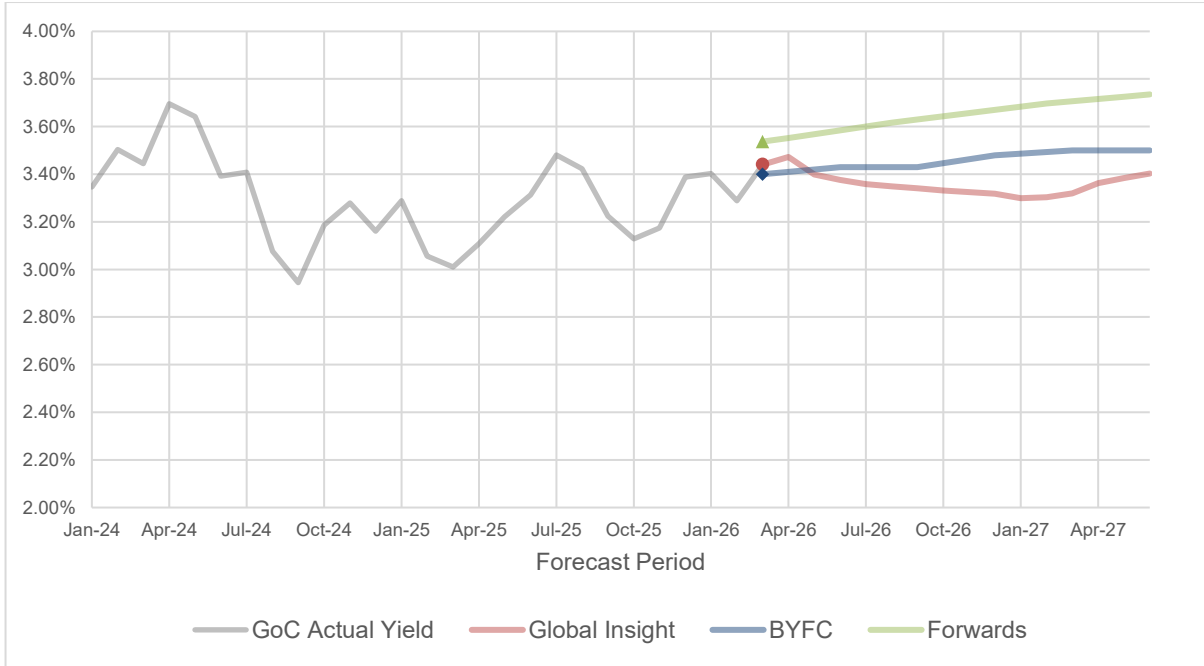
**Figure 26: 10-Year Actual GoC and Forecasts in February 2026**



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**Figure 27: 10-Year Actual GoC and Forecasts in March 2026**



3

**Board Staff Interrogatory #032**

**Interrogatory**

**Reference:**

**Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / p. 9**

**Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Table 1b**

**Preamble:**

OPG stated that in 2022, it entered into a \$970 million non-revolving term credit facility with the Canada Infrastructure Bank (CIB). The facility was made available to fund part of the expenditures required to prepare for the construction of the Darlington New Nuclear Program (DNNP). The debt outstanding under the CIB facility will remain with OPG following the transfer of the DNNP facilities to DNNP LP.

OPG stated that as it will no longer be associated with OPG's prescribed facilities, this debt is excluded from that attributed to OPG's regulated operations. Instead, under the expected partnership arrangements, OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026.

OPG stated that this forecast credit or charge is reflected in the DNNP LP's proposed revenue requirements over the IR term (Ex. F2-1-1, Table 1b, line 7). OEB staff notes that this is specifically included as "Asset Service Fees" in DNNP's OM&A.

**Question(s):**

- a) Please explain why OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026.

**Response**

The referenced statement in the pre-filed evidence was based on the expectations of the pricing methodologies that would be reflected for the services to be provided by OPG to DNNP LP under the Management, Operations, Maintenance and Administration agreement that would be put in place between the parties in respect of the DNNP facilities. The parties have since then entered into this agreement, which pricing methodologies include the provisions for the above noted credit (or charge) as anticipated in the pre-filed evidence, as set out at Ex. L-A1-CCC-010, Attachment 4, p. 65. As discussed at Ex. L-C1-SEC-040 part d), this amount is a forecast credit for

1 all years 2026-2031 and therefore reduces DNNP LP's proposed revenue  
2 requirements.

3

4 O. Reg. 53/05, section 14(2)5(iii) requires the OEB to accept, in setting payment  
5 amounts for the DNNP facilities, "the terms, conditions and pricing methodologies  
6 included in any project management, operations, revenue allocation or lease  
7 agreements between the DNNP generator and Ontario Power Generation Inc. in  
8 respect of the DNNP Nuclear Generating Station".

**Board Staff Interrogatory #033**

**Interrogatory**

**Reference:**

**Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1 – 6**

**Ref 2: Exhibit C1 / Tab 1 / Schedule 2 / p. 6**

**Preamble:**

OPG staff has prepared the following table, summarizing OPG’s proposed long-term debt rate requests, which were derived from using OPG’s current methodology (versus the methodologies used in prior applications).

**Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates**

<b>Year</b>	<b>Proposed Long-Term Debt Rate</b>
2026	4.42%
2027	4.58%
2028	4.78%
2029	4.90%
2030	4.97%
2031	4.98%

In a footnote, OPG suggested that the Bloomberg data incorporated into the above-noted proposed long-term debt rates were obtained on November 21, 2025.

**Question(s):**

- a) Please confirm that “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates” is accurate.
- b) If this is not the case, please update “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates” and explain any changes made.

- 1 c) Please update “Table 1 – Summary of OPG’s Proposed Long-Term Debt Rates”  
 2 using OPG’s methodology from its last payments proceeding (by adding a new  
 3 column) and summarize the assumptions made to derive these long-term debt  
 4 rates.  
 5  
 6 d) With the results of part c), please re-run the proposed revenue requirements for  
 7 2027-2031 using the old methodology.  
 8  
 9

10 **Response**

- 11  
 12 a) Confirmed.  
 13  
 14 b) Not applicable.  
 15  
 16 c) OPG has not introduced a new methodology for forecasting the cost of its long-term  
 17 debt. As noted at Ex. C1-1-2, p. 5, lines 15-17, OPG continues to forecast the cost  
 18 of planned debt issues based on a forecast of Government of Canada (“GoC”) bond  
 19 rates for the applicable tenor and an observed credit spread. OPG has made certain  
 20 updates and improvements to the methodology and its application, including with  
 21 respect to the basis for the observed credit spread, as outlined at Ex. C1-1-2, p. 5,  
 22 line 19 to p. 6, line 25.  
 23

24 In Chart 1 below, OPG has reproduced the Table provided in the question, using  
 25 1) the Global Insight 10-year GoC bond yield forecast dated November 17, 2025  
 26 and an OPG spread and issuance cost of 1.13% as at the same date, and 2) the  
 27 Global Insight 10-year GoC bond yield forecast dated March 17, 2026 and an OPG  
 28 spread and issuance cost of 1.17% as at the same date. As the prior payment  
 29 amounts proceeding did not reflect any 30-year bond issuances in the forecast  
 30 long-term debt rates, none have been assumed in Chart 1 below.  
 31

32 **Chart 1 – Summary of OPG’s Proposed Long-Term Debt Rates**

33

Year	Proposed Long-Term Debt Rate	Proposed Long-Term Debt Rate using OPG’s methodology from its last payments proceeding (November 17, 2025)	Proposed Long-Term Debt Rate using OPG’s methodology from its last payments proceeding (March 17, 2026)
2026	4.42%	4.42%	4.42%
2027	4.58%	4.37%	4.46%
2028	4.78%	4.30%	4.54%
2029	4.90%	4.23%	4.55%
2030	4.97%	4.19%	4.55%
2031	4.98%	4.19%	4.55%

1 OPG observes that there would be significant flaws with the use of the above  
 2 information for purposes of forecasting OPG's long-term debt cost. First, as  
 3 discussed in Ex. C1-1-2 and Ex. L-C1-Staff-029, part b), the above calculations  
 4 ignore the fact that, in addition to 10-year debt, OPG typically issues 30-year debt.  
 5 Second, as also discussed at Ex. L-C1-Staff-029, part c), these calculations rely on  
 6 GoC forecasts that have significant unexplained variability compared to other  
 7 sources. Finally, the rates in Chart 1 fail to take advantage of more diverse and  
 8 transparent forecasting sources for the GoC rates available in the form of the  
 9 Bloomberg Bond Yield Median Forecast and forward rates, and rely on one-day,  
 10 rather than a series of, observations for credit spreads (refer to Ex. L-C1-Staff-031,  
 11 part b)). For these reasons, the Applicants do not consider these forecasts to be  
 12 sufficiently reliable or reflective of economic expectations and believe that they  
 13 should not be used for purposes of setting payment amounts in this proceeding.  
 14

- 15 d) To perform the requested hypothetical calculations, the Applicants adjusted the  
 16 cost of long-term debt in Ex. C1-1-1, Tables 1-5 using the rates in Chart 1, holding  
 17 all other variables constant. Adjusting the long-term debt rate impacts the proposed  
 18 cost of capital, concurrent cost recovery interest amounts, and the calculations of  
 19 asset service fees. The results are summarized in Chart 2 and Chart 3, below.  
 20

21 **Chart 2 – Hypothetical Revenue Requirement Using Chart 1 Long-Term Debt**  
 22 **Rates as of November 17, 2025**  
 23

Year	OPG Nuclear Facilities	DNNP Facilities	Regulated Hydroelectric
<b>Proposed</b>			
2027	4,062.8	301.0	1,668.3
2028	4,257.4	378.8	
2029	4,677.0	404.9	
2030	4,882.4	559.3	
2031	5,737.6	1,042.0	
<b>Hypothetical (November 17, 2025)</b>			
2027	4,034.2	294.2	1,659.5
2028	4,171.6	356.8	
2029	4,534.0	370.4	
2030	4,690.5	530.1	
2031	5,546.4	1,051.9	

24

**Chart 3 – Hypothetical Revenue Requirement Using Chart 1 Long-Term Debt Rates as of March 17, 2026**

<b>Year</b>	<b>OPG Nuclear Facilities</b>	<b>DNNP Facilities</b>	<b>Regulated Hydroelectric</b>
<b>Proposed</b>			
2027	4,062.8	301.0	1,668.3
2028	4,257.4	378.8	
2029	4,677.0	404.9	
2030	4,882.4	559.3	
2031	5,737.6	1,042.0	
<b>Hypothetical (March 17, 2026)</b>			
2027	4,046.3	297.1	1,663.3
2028	4,214.2	367.7	
2029	4,602.2	386.8	
2030	4,779.4	543.6	
2031	5,633.2	1,047.4	

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**Board Staff Interrogatory #034**

**Interrogatory**

**Reference:**

**Exhibit C1 / Tab 1 / Schedule 2 / p. 2**

**Preamble:**

OPG stated that it expects most of its borrowing needs over the IR term to be sourced through its Medium-Term Note program in the Canadian bond market. OPG is also planning to establish the ability to access US bond markets during the IR term, as part of its funding risk diversification strategy to proactively manage the likelihood that its funding requirements will exceed the issuance capacity in the Canadian bond markets. OPG intends to accomplish this by registering as a Foreign Private Issuer with the U.S. Securities and Exchange Commission (SEC). OPG stated that the cost of debt assumptions in the current application are based on bond issuances in the Canadian market.

OEB staff notes that IFRS 20, Regulatory Assets and Regulatory Liabilities, is expected to be issued by the International Accounting Standards Board (IASB) by Q2 2026.

**Question(s):**

- a) Please explain why it is likely that OPG's "funding requirements will exceed the issuance capacity in the Canadian bond markets."
- b) Please explain whether registering with the SEC would prohibit OPG to move to IFRS from US GAAP for financial reporting purposes and regulatory reporting and rate-making purposes.

**Response**

- a) As stated at Ex. C1-1-2, p. 2, "OPG is also planning to establish the ability to access US bond markets during the IR term [...] to proactively manage the likelihood that its funding requirements will exceed the issuance capacity in the Canadian bond markets." As such, while OPG is looking to proactively manage the risk of such an outcome, it has not yet confirmed how likely this outcome is to occur during the IR term. Whether OPG's funding requirements will exceed the issuance capacity in the Canadian bond markets will depend on factors largely outside of OPG's control. Such factors could include broader macroeconomic/financial market conditions, Canadian investor appetite for fixed income products generally and OPG's CAD-

1       denominated bonds specifically, and the volume of competing supply from other  
2       issuers at the time when OPG is requiring bond funding. By proactively establishing  
3       the ability to issue bonds in another market, OPG will have alternative options to  
4       mitigate its funding risk, should some of these risk factors manifest.

5  
6       To manage the above risk, OPG is planning to establish the ability to issue US  
7       Securities and Exchange Commission (“SEC”) registered bonds during the IR term.  
8       The US bond market is the largest, deepest, and most liquid funding market  
9       globally, and is typically the next jurisdiction for Canadian bond issuers to source  
10      funding following the establishment of a domestic Canadian program. SEC-  
11      registered bonds provide the most competitive pricing for issuers accessing the US  
12      bond market when compared to unregistered alternatives, as certain investors are  
13      unable to purchase unregistered bonds.

- 14  
15     b) Registering with the SEC would not in and of itself prohibit OPG from moving to  
16     IFRS from US GAAP for continuous disclosure purposes, or from moving to IFRS  
17     for regulatory purposes in the future.<sup>1,2</sup> However, a transition to IFRS for continuous  
18     disclosure purposes in such circumstances would fail to take advantage of the  
19     permission granted under National Instrument 52-107, which provides that financial  
20     statements for a Canadian reporting issuer that is also a SEC registrant may be  
21     prepared in accordance with US GAAP. The continued use of US GAAP for both  
22     US and Canadian continuous disclosure purposes would minimize potential  
23     investor confusion and facilitate comparability with peer issuers in the US bond  
24     market. Transitioning to IFRS for regulatory purposes while continuing to conduct  
25     financial reporting under US GAAP would create a significant administrative burden  
26     for OPG in fulfilling its continuous disclosure reporting obligations.

27  
28     Once it becomes a SEC registrant, OPG plans to continue using US GAAP for  
29     continuous disclosure purposes and not to seek moving to IFRS for regulatory  
30     purposes.

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<sup>1</sup> Refer to Ex. A2-1-1, Section 2.0 and Ex. L-H1-01-Staff-263 for a further discussion of OPG’s continuous disclosure obligations related to the basis of financial reporting.

<sup>2</sup> As discussed in Ex. L-H1-01-Staff-262, the OEB’s current filing requirements require it to prepare payment amounts applications using US GAAP.

**Board Staff Interrogatory #035**

**Interrogatory**

**Reference:**

**Ref 1: Exhibit C1 / Tab 1 / Schedule 3 / pp. 2-3**

**Preamble:**

For the source of the forecasted 3-month T-Bill rate for 2025-2027, OPG has used the equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC).

For the source of the forecasted 3-month T-Bill rate for 2028-2031, the forecast has been inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.

**Question(s):**

- a) Please confirm that OEB staff's understanding of the sources of the forecasted 3-month T-Bill rate for 2025-2031 noted in the above Preamble is correct. If this is not the case, please explain.
- b) Please explain why it is appropriate to use the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) to develop both OPG's long-term debt rates and short-term debt rates.
- c) OEB staff was unable to find the relevant data for the tickers BYFC, YCGT0007, and YCSW0147 on Bloomberg's platform, despite the OEB holding a Bloomberg subscription. Please explain, step-by-step, how OPG derives the data from these tickers, and how they are included in the derivation of OPG's long-term debt costs and short-term debt costs. For example, instead of using the ticker BYFC, please explain whether OPG instead used the following Bloomberg tickers to develop its forecasts:
  - i. EC30CA Q426 Index for its Canada 30-Year Note Forecast
  - ii. ECXYCA Q426 Index for its Canada 10-Year Bond Yield Forecast
  - iii. EC3MCA Q426 Index for its Canada 3-month Interest Rate Forecast
- d) Please explain why OPG has used the equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147

1 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC), instead of different  
2 proportions.  
3

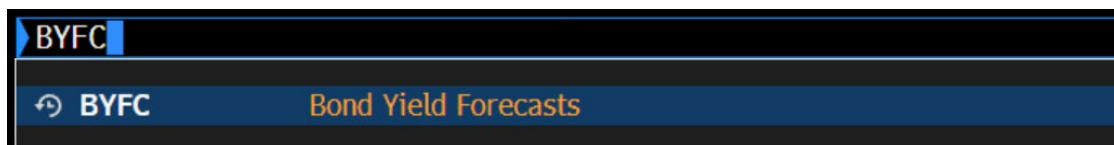
4  
5 **Response**  
6

- 7 a) Not confirmed. The 2025 forecasted three-month benchmark “risk-free” rate is  
8 based on the average yield on OPG’s commercial paper issued from January 1,  
9 2025, to November 12, 2025. The OEB staff’s understanding of the sources of the  
10 forecasted three-month T-Bill rate for 2026-2031 in the above Preamble is correct.  
11
- 12 b) Refer to Ex. L-C1-Staff-029 part d) for the reasons OPG has used a combination of  
13 Bloomberg Bond Yield Median Forecasts (10-year and 30-year for long-term debt,  
14 and the three-month T-Bill for short-term debt) and Bloomberg forward rates (10-  
15 year and 30-year for long-term debt, and the three-month OIS for short-term debt),  
16 in order to develop the forecasted long-term and short-term debt rates in this  
17 Application.  
18
- 19 c) OPG confirms it has used the tickers BYFC, YCGT0007, and YCSW0147 on  
20 Bloomberg’s platform as noted in the pre-filed evidence. For ease of reference,  
21 OPG has outlined the steps to access each of these tickers.  
22

23 Steps to access BYFC are as follows:  
24

- 25 1. Key in BYFC in the command line at the top left corner and press Enter (Figure  
26 1).  
27

28 **Figure 1 – BFYC Search on Bloomberg**  
29



- In the dropdown menu, ensure that '3 Month – 30 Year' is selected and Canada specific data is displayed (Figure 2).

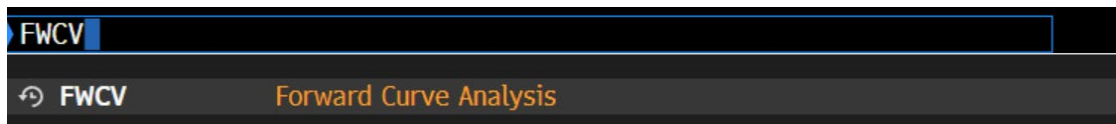
**Figure 2 – BFYC Screen on Bloomberg**

	Mkt Yld	Q1 26	Q2 26	Q3 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27	Q1 28	Q2 28
1) Japan 2-Year	1.26	1.22	1.29	1.37	1.41	1.50	1.56	1.43	1.43	1.42	1.38
1) Japan 3-Month Tibor	1.27	1.07	1.18	1.26	1.32	1.38	1.40	1.40	1.40	1.38	1.32
2) BOJ Target Rate	.75	.76	.87	.98	1.10	1.15	1.20	1.22	1.30	1.29	1.27
Canada											
2) Canada 30-Year	3.95	3.82	3.79	3.77	3.76	3.78	3.80	3.81	3.83	3.68	3.68
2) Canada 10-Year	3.50	3.40	3.39	3.40	3.41	3.46	3.50	3.54	3.55	3.49	3.50
2) Canada 2-Year	2.77	2.57	2.55	2.60	2.65	2.70	2.77	2.82	2.87	2.75	2.75
2) Canada 3-Month Bill	2.24	2.21	2.22	2.24	2.31	2.46	2.55	2.64	2.71	2.52	2.52
2) BOC Overnight Lending Rate	2.25	2.25	2.25	2.25	2.30	2.41	2.50	2.60	2.68	2.61	2.61
2) 3-Month CORRA	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.35		

Steps to access YCGT0007 and YCSW0147 on FWCV are as follows:

- Key in FWCV in the command line at the top left corner and press Enter (Figure 3).

**Figure 3 – FWCV Search on Bloomberg**



- Key in YCGT0007 in the orange box on the top left corner; this represents the Canada Sovereign Curve (Figure 4).

**Figure 4 – YCGT0007 on FWCV Screen on Bloomberg**

Add Columns		Table		Graph	
<input checked="" type="checkbox"/>	1 Mo	Tenor	Spot (%)	1 Mo (%)	3 Mo (%)
<input checked="" type="checkbox"/>	3 Mo				

- Click the "Implied Forwards" button in the top left, then choose the desired parameters in the orange boxes, including the tenor. In Figure 5, the 10-year tenor is selected, representing the Government of Canada 10-year bond forward rates.

Figure 5 – GoC 10-Year Bond Forward Rates

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YCGT0007		Curve List	Export ▾	Settings ▾
Curve Date	03/12/26	Market	Mid	
Horizon Curve   Implied Forwards				
From	03/12/26	Up to	30 Yr	Interval 1 Mo Tenor 10 Yr
Table   Graph				
CAD Canada Sovereign Curve				
Date	Zero Rate	Forward Rate		
03/12/2026		3.5416		
04/12/2026	2.1793	3.5589		
05/12/2026	2.2053	3.5753		
06/12/2026	2.2144	3.5923		
07/12/2026	2.2445	3.6078		
08/12/2026	2.2674	3.6236		
09/12/2026	2.3029	3.6385		

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6. To access YCSW0147, repeat steps 1 to 3, replacing YCGT0007 with YCSW0147. Choose a three-month tenor to represent the three-month OIS rates (Figure 6).

Figure 6 – OIS Three-Month Forward Rates

10

YCSW0147		Curve List	Export ▾	Settings ▾
Curve Date	03/12/26	Market	Mid	
Horizon Curve   Implied Forwards				
From	03/12/26	Up to	30 Yr	Interval 1 Mo Tenor 3 Mo
Table   Graph				
CAD OIS				
Date	Zero Rate	Forward R...		
03/12/2026		2.2582		
04/12/2026	2.2532	2.2814		
05/12/2026	2.2549	2.3370		
06/12/2026	2.2582	2.3997		
07/12/2026	2.2742	2.4761		
08/12/2026	2.3043	2.5242		
09/12/2026	2.3290	2.5625		
10/12/2026	2.3610	2.6056		
11/12/2026	2.3868	2.6491		
12/12/2026	2.4063	2.6910		

11

1  
2 d) The three-month forward Overnight Index Swap from the Bloomberg ticker reflects  
3 the market implied forward curve, while the Bloomberg Bond Yield Median Forecast  
4 represents the consensus view of economists. Averaging of these two data sets  
5 provides a broader, more balanced perspective on future interest rate movements,  
6 for the same reasons as discussed in Ex. L-C1-Staff-029, part d), and is consistent  
7 with the long-term debt interest forecast methodology, which is also discussed in  
8 that interrogatory.

**Board Staff Interrogatory #054**

**Interrogatory**

**Reference:**

**Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 63**

Preamble:

Concentric stated the following:

OPG's prescribed assets represent 100% rate-regulated generation, and companies in the proxy group should reflect the heightened risk profile of generating assets, especially as investors generally attribute higher risk to utilities with generation assets than those with only transmission or distribution operations. This is highlighted in Moody's 2024 ratings methodology for regulated electric and gas utilities: "[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

- a) Concentric: Please provide the following for each utility included in the Main Peer Group using the most recently available data:
- i. The dollar value of nuclear generation plant-in-service
  - ii. The dollar value of hydroelectric generation plant-in-service
  - iii. The dollar value of total plant-in-service

**Response**

*This response was prepared by Concentric Energy Advisors ("Concentric")*

- a) Please see the requested values provided in Excel format in Attachment 1.