CCC Interrogatory #24

Interrogatory

Reference: Exhibit C1/T1/S1/p. 2

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

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

Response

a) The calculation of the revenue requirement impact of a 100 basis point change in Return on Equity ("ROE") is provided in response to Ex. L-C1-01-LPMA-007, Attachment 1. The impact to the proposed 2022 revenue requirement would be a decrease of $57.6M.

b) No.

In EB-2016-0152, OPG proposed a Nuclear ROE Variance account to capture the revenue requirement difference between the ROE approved by the OEB for the purposes of the nuclear revenue requirement for 2018-2021 and the actual annually updated ROE specified by the OEB.[1] The OEB found that the proposed variance account was "analogous to an annual cost of capital update, and thus inconsistent with the OEB's intentions in the Rate Handbook."[2] Accordingly, OPG has not proposed an annual update to the ROE in this application.

c) If the OEB undertakes a Generic Cost of Capital Review during the IR period, OPG would assess the outcomes of that review and the OEB's reasons for those outcomes to determine what options, if any, are available to the company.

[1] EB-2016-0152, Ex. H1-1-1 p. 31.
[2] EB-2016-0152, Decision and Order, p. 111.

CCC Interrogatory #25

Interrogatory

Reference: Exhibit C1/T1/S2 – Concentric Report

Torys has retained Concentric Energy Advisors to prepare a Common Equity Ratio Study on behalf of OPG:

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

Response

a) See Ex. L-A1-02-CCC-001, part d).

b) See Ex. L-A1-02-CCC-001, part f) regarding Torys' role in the report. OPG provided any information requested by Concentric Energy Advisors to formulate its opinion and report.

CCC Interrogatory #26

Interrogatory

Reference: Exhibit C1/T1/S1

Please set out the allowed ROE and actual ROE for each year 2017-2021. Please provide a detailed variance analysis.

Response

Refer to Ex. L-I1-01-SEC-159.

CCC Interrogatory #27

Interrogatory

Reference: Exhibit C1/T1/S1

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

Response

Attachment 1, Tables 1-5 provide the Summary of Capitalization and Cost of Capital assuming a 45% Equity Level for 2022-2026.

Attachment 1, Table 6 provides the variance in nuclear revenue requirement, and therefore the impact on the revenue deficiency, for 2022-2026 as between using the existing and proposed capital structure.

Table 1
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital Assuming a 45% Equity Level
Calendar Year Ending December 31, 2026

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.4%	2.23%	7.2
2	**Existing/Planned Long-Term Debt**	2	3,680.9	16.6%	3.65%	134.5
3	**Other Long-Term Debt Provision**	3	8,426.0	38.0%	3.65%	307.9
4	**Total Debt**	4	12,204.3	55.0%	3.68%	449.6
5	**Common Equity**	4	9,985.3	45.0%	8.34%	832.8
6	**Rate Base Financed by Capital Structure**	5	22,189.6	100.0%	5.78%	1,282.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		22,189.6	100%	5.78%	1,282.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 12, line 26.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 45% equity level as requested in C1-01-CCC-027

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital Assuming a 45% Equity Level
Calendar Year Ending December 31, 2025

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.5%	1.66%	6.7
2	**Existing/Planned Long-Term Debt**	2	3,686.2	17.6%	3.65%	134.7
3	**Other Long-Term Debt Provision**	3	7,756.0	37.0%	3.65%	283.4
4	**Total Debt**	4	11,539.5	55.0%	3.68%	424.7
5	**Common Equity**	4	9,441.4	45.0%	8.34%	787.4
6	**Rate Base Financed by Capital Structure**	5	20,980.9	100.0%	5.78%	1,212.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		20,980.9	100%	5.78%	1,212.1

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 11, line 26.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 45% equity level as requested in C1-01-CCC-027

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Table 3
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital Assuming a 45% Equity Level
Calendar Year Ending December 31, 2024

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.5%	1.16%	6.2
2	**Existing/Planned Long-Term Debt**	2	3,764.6	19.4%	3.61%	136.0
3	**Other Long-Term Debt Provision**	3	6,831.7	35.1%	3.61%	246.9
4	**Total Debt**	4	10,693.6	55.0%	3.64%	389.1
5	**Common Equity**	4	8,749.3	45.0%	8.34%	729.7
6	**Rate Base Financed by Capital Structure**	5	19,443.0	100.0%	5.75%	1,118.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		19,443.0	100%	5.75%	1,118.8

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 10, line 27.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 45% equity level as requested in C1-01-CCC-027

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital Assuming a 45% Equity Level
Calendar Year Ending December 31, 2023

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.6%	0.78%	5.8
2	**Existing/Planned Long-Term Debt**	2	4,039.6	24.0%	3.49%	140.8
3	**Other Long-Term Debt Provision**	3	5,117.8	30.4%	3.49%	178.4
4	**Total Debt**	4	9,254.8	55.0%	3.51%	325.0
5	**Common Equity**	4	7,572.1	45.0%	8.34%	631.5
6	**Rate Base Financed by Capital Structure**	5	16,826.8	100.0%	5.68%	956.5
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		16,826.8	100%	5.68%	956.5

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 9, line 29.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 45% equity level as requested in C1-01-CCC-027

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital Assuming a 45% Equity Level
Calendar Year Ending December 31, 2022

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.6%	0.47%	5.5
2	**Existing/Planned Long-Term Debt**	2	3,837.8	23.3%	3.61%	138.4
3	**Other Long-Term Debt Provision**	3	5,130.0	31.1%	3.61%	184.9
4	**Total Debt**	4	9,065.1	55.0%	3.63%	328.8
5	**Common Equity**	4	7,416.9	45.0%	8.34%	618.6
6	**Rate Base Financed by Capital Structure**	5	16,482.0	99.6%	5.75%	947.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	73.6	0.4%	4.89%	3.6
8	**Rate Base**		16,555.6	100%	5.74%	951.0

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 8, line 35.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 45% equity level as requested in C1-01-CCC-027

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Table 6
Calculation of Cost of Capital Using Current and Proposed Capital Structure ($M)

Line No.	Description	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)
1	**Nuclear Rate Base**[1]	8,646.8	8,788.7	11,260.7	12,468.5	13,312.0
2	**ROE**[2]	8.34%	8.34%	8.34%	8.34%	8.34%
3	**Cost of Debt**[2]	3.63%	3.51%	3.64%	3.68%	3.69%
4	**Deemed Equity (Proposed)**[2]	50%	50%	50%	50%	50%
5	**Deemed Debt (Proposed)**[2]	50%	50%	50%	50%	50%
6	**Proposed WACC**[3]	6.0%	5.9%	6.0%	6.0%	6.0%
7	**Deemed Equity (EB-2016-0152)**	45%	45%	45%	45%	45%
8	**Deemed Debt (EB-2016-0152)**	55%	55%	55%	55%	55%
9	**Proposed WACC (At EB-2016-0152 Capital Structure)**[4]	5.7%	5.7%	5.8%	5.8%	5.8%
10	**Revenue Requirement (Proposed)**[5]	637.7	643.1	831.1	922.9	985.6
11	**Revenue Requirement (At EB-2016-0152 Capital Structure)**[6]	605.3	609.7	789.0	876.5	936.1
9	**Revenue Requirement Impact if EB-2016-0152 Capital Structure is Maintained**[7]	**(32.4)**	**(33.4)**	**(42.1)**	**(46.4)**	**(49.5)**

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

CCC Interrogatory #28

Interrogatory

Reference: Exhibit C1/T1/S2/Table 7a

OPG has planned Long-term Debt Issues for 2021. Please provide an update once these have been completed.

Response

None of the planned long-term debt issues for 2021 at Ex. C1-1-2, Table 7a have yet been completed.

CME Interrogatory #24

Interrogatory

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

Concentric stated "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."

(a) Please provide the survey questions and full answers provided from the analysts interviewed as part of your report.

Response

Response prepared by Concentric Energy Advisors

See Attachment 1.

The following are notes taken during interviews with Canadian equity analysts and North American credit analysts.

Question	Responses
Please describe your role as an analyst/investor covering or investing in the utility sector.	• Canadian equity analyst covering utility sector, following utilities, pipelines, and energy companies. • Canadian equity analyst, covers Canadian infrastructure sector (reg util, power gen, pipeline stocks), covers large Canadian utility stocks. • Canadian equity analyst covering the utility sector. • Three credit analysts covering North American utility sector. • Credit analyst covering all Canadian regulated utilities and back-up analyst on U.S. companies.
Does your coverage or investing universe include Canadian and U.S. utilities?	• Covers Canadian companies with significant US operations, share information and discusses themes with analysis in NY that covers U.S. names. (Canadian equity analyst) • Coverage is Canadian only but since many Canadian utilities own U.S. affiliates analyst is also familiar with US to some extent; US counterpart provides coverage of US operations of Canadian companies; talks multiple times per week with US counterpart to share what they are hearing about companies and investment themes. (Canadian equity analyst) • Covers Canadian publicly traded companies, but many of the names analyst follows have more than 50% of assets in the U.S. As such, analyst actively follows the U.S. regulatory and capital market trends. (Canadian equity analyst) • North American regulated utility team – includes IOUs and govt owned – folks in Canada primarily cover Canadian companies with overlap into U.S. – people in US follow U.S. utilities. (North American credit analyst) • Credit analyst covering all Canadian regulated utilities and back-up analyst on U.S. companies. (North American credit analyst)
Do you factor in country risk in making your ratings or investment decisions?	• Yes, but primarily for assets held outside Canada and US. Treat Canada and US fairly similar. Spread between US and Canadian 10-year bonds is 20 bps, view as rounding error, view country risk as minor, focus more on jurisdiction than country. (Canadian equity analyst)

Question	Responses
	• Considers country risk, but gap is less between Canada and US than it would be for investments by utilities in emerging markets countries. Differences are more jurisdictional (provincial vs. state) than Canada vs. U.S. Regulatory environment is more homogeneous in Canada than in U.S. (Canadian equity analyst) • Analyst generally treats Canada and U.S. the same unless there is a large divergence in risk-free rate. Tends to place a higher risk profile to countries outside of North America. (Canadian equity analyst) • Rating process includes country risk – same very low risk for U.S. and Canada – has applied same country risk criteria for both countries since 2013. (North American credit analyst) • Canada is AAA; U.S. is AAA, much more of an issue when there is a country or provincial ceiling. Firm is entirely focused on OEB for OPG. If firm sees something big in another jurisdiction, they will ask OEB about that. (North American credit analyst)
Do you see the regulatory environment in Canada as providing any more or less risk protection and support to utilities than the US regulatory environment?	• Each jurisdiction is a little different; Canadian regulatory framework has generally been superior to U.S. based on limited history of disallowances, forward test years, and incentive ratemaking frameworks that allow utilities to earn better return; however, Canadian framework has been very static, while U.S. regulatory environment has been improving – more use of forward test years, more weather normalization, improved ability to earn authorized return. (Canadian equity analyst) • In aggregate, they view Canada as being less risky than US, but they consider differences between jurisdictions as more important. (Canadian equity analyst) • Other than select cases, I have found that the Canadian regulatory environment is more supportive relative to the U.S. (Canadian equity analyst) • Assessment is more focused on four pillars – regulatory stability, tariff setting, financial stability, regulatory independence and insulation. (North American credit analyst)

Question	Responses
	• How to compare FL to NM to CA, for instance? At a high level, consider Canada to be more favorable than US – not wholly stepped out – but on average more credit supportive. HONI has had historical challenges with OEB – not on the same page as OEB in 2015, but HONI has gotten better at understanding what the OEB wants. OPG is unique/unusual because they have 100% regulated generation. Increased risk associated with nuclear refurbishment. No one ever associates nuclear refurbishment with low execution risk. Rating factors grid – a couple of factors for regulation (4 scores). Canadian provinces tend to score higher, except for OPG. OPG – on timeliness of recovery of capital costs, OPG does not score as high (see nuclear refurbishment). OEB has said OPG is not an efficient company – hard to earn ROE where you have disallowances such as OPG has had. Besides HONI, unaware of cost disallowances on level seen by OPG. Biggest challenge is inefficiency. OEB may say "we'll talk when you're more efficient." (North American credit analyst)
If so, what factors specifically lead you to this conclusion? (test year, cost recovery, regulatory lag, ability to earn allowed return, deferral/variance accounts, other?)	• Regulatory and deferral accounts are complex; look at in aggregate but not on account by account basis; look at ability to earn return and generate cash flow. (Canadian equity analyst) • Most provinces have forward test years in Canada, hodgepodge of test years in U.S. jurisdictions. Most Canadian utilities have formal or informal decoupling in rates, in U.S. it is all over the map. Fewer provinces that matter in Canada because there are few with IOUs. Canada has more pre-approval of capital plans, which reduces risk of capital disallowance. Canada uses more DVA, which lowers band around authorized return. Canada is much closer to COS model than U.S. (Canadian equity analyst) • Canadian regulation tends to be a forward test year approach, cost recovery is predictable, and ability to earn or exceed allowed ROE's is the norm. In the U.S., there tends to be more regulatory lag and historical test years are more common and earnings are less predictable. Analyst does acknowledge that U.S. allowed ROEs are higher than Canada, which partially offsets the lag. And U.S. utilities in recent years have come back for more frequent rate

Question	Responses
	cases and requesting additional variance accounts to smooth earnings i.e. weather normalization. (Canadian equity analyst) • Base rate recovery, cost recovery, infrastructure riders, cash flow support to keep spending while maintaining financial measures – small differences between jurisdictions that are generally credit supportive – jurisdiction by jurisdiction analysis – consistency of decisions is another consideration – transparency and predictability. (North American credit analyst) • Unrecovered labor costs at OPG are biggest issue. Have cost disallowances. Directionally, they have a reasonably good set up. Forecast rates and CapEx – very favorable; depreciation lagging? $100-$200mm in cost disallowances. From shareholder perspective, don't want total contemporaneous recovery if it reduces rate base. Finds that incentives lead to performance (see UK and former incentives around capex vs. opex). Can't see IOU shareholder sustaining $100mm loss the way that province has sustained OPG $100mm disallowance; can't see IOU CEO answering that question on a shareholder call. (North American credit analyst)
Do you factor in provincial or state level regulatory risk in making your ratings or investment decisions? If so, please explain the factors you consider.	• Firm has internal ranking of each regulatory body; assets in more favorable jurisdictions get better valuations, while less favorable jurisdictions get lower valuation, ranking not available publicly. (Canadian equity analyst) • Yes, see other responses. (Canadian equity analyst) • I do. For example, a Canadian utility is their #1 investment idea mainly given that half their assets are in a U.S. state where there are high allowed ROEs, the support for rate base investment/storm hardening is strong, and customers relationships are solid (less controversial settlement agreements). In contrast, we are neutral on a Canadian utility given its material exposure to a Canadian province where we've seen a number of negative regulatory trends including having one of the lowest allowed ROEs in the country and lingering stranded asset risk. (Canadian equity analyst) • Yes, see above. Fine gradations between credit supportive and most credit supportive jurisdictions. (North American credit analyst) • See previous responses. (North American credit analyst)

Question	Responses
Do you consider the Ontario regulatory environment more or less supportive than the average Canadian or U.S. jurisdiction? If so, please explain why.	• Like OEB's ability for utilities to ask for multi-year incentive ratemaking framework, provides rate certainty for customers and motivation to control costs for utility; like forward test year in Ontario; like COVID related cost treatment of OEB. Equity thickness and ROE in Ontario is inferior to many other jurisdictions, especially in US. Historically, delta would have been OK, but with improving regulatory framework in US, the ROE and equity thickness in Ontario could lead to challenges in incenting capital to flow to province. Don't believe formulaic ROE in Ontario is accurately reflecting the cost of equity. Increase in political risk in Ontario and potential that government wields power in regulatory space, increases risk profile of utilities. No reason for risk differential between Canada and US. Equity ratios and ROE should be similar. (Canadian equity analyst) • Nothing stands out as being more positive/negative in Ontario vs other Canadian provinces. Canada has lower risk than US jurisdictions on average, but depends on specific jurisdiction. Agrees that directionally U.S. has narrowed gap in terms of regulatory environment with Canada (not familiar with all 50 states). (Canadian equity analyst) • Views the Ontario regulatory environment as balanced (and perhaps slightly more supportive than other Canadian jurisdictions). While there tends to be costs disallowances (especially compensation and capex), it is not overly punitive in analyst's view. The formulaic ROE adjustment mechanism is visible as it is driven by specific quantitative inputs (unlike other Canadian jurisdictions where there is less certainty during cost of capital reviews); there is incentive regulation allowing ability to over-earn. Acknowledges there has been several OEB decisions that left firm scratching its head, such as the recent deferred tax disallowance towards Hydro One, but on the whole the OEB strikes a balance between the consumer and companies. (Canadian equity analyst) • Rate setting process uses PBR; custom incentive ratemaking feature is helpful for companies with large capex, helps with financial stability of utilities, ROE is formula driven – provides consistency and predictability, govt intervention – OEB has streamlined rate adjudication process and

Question	Responses
	increased independence through changes to organization. ROE level is not critical, but important thing is ability to earn ROE because it provides cash flow, authorized returns need to cover cost of equity. (North American credit analyst) • See previous responses. (North American credit analyst)
Do you consider electric generation more or less risky than electric distribution and transmission, or comparable? Please elaborate.	• Generation is more risky than T&D assets. More risk associated with operations, loss of life, catastrophic failure, site/environmental risk. (Canadian equity analyst) • Views generation as more risky than T&D assets, greater risk of economic obsolescence with generation, greater risk of forced outages. (Canadian equity analyst) • Historically I would say no as generation in rate base is still entitled to earn a return on and of capital similar to T&D. That said, with the emergence of ESG esp. since late 2018, I have found that investors tend to prefer companies with lower generation assets and more T&D. If generation is owned, the preference is renewables over non-renewables. I believe that in today's market, there is a higher risk profile allocated to generation over T&D. (Canadian equity analyst) • Generation has higher risk according to criteria – affects financial risk; T&D has lower operating risk profile than generation; environmental risk, AROs, coal ash; reflected in what financial benchmark table gets used to assess financial risk. (North American credit analyst) • Riskiest type – refurbishment nuclear or new build. (North American credit analyst)
Do you consider a company with a nuclear generating fleet more, less or of comparable risk to a comparable company without	• Does not have specific view on OPG nuclear. In general, nuclear is most risky of generation types due to possibility of catastrophic failure, loss of life, and damage to environment. (Canadian equity analyst) • Nuclear generation has more risk around decommissioning and spent fuel; risk of catastrophic event is relatively low but very important. Ontario govt is supportive of nuclear being in mix as evidenced by refurbishment of Pickering and Darlington. Risk of economic obsolescence is lower for nuclear; on balance, nuclear is more risky than other generation types. At

Question	Responses
nuclear generation? Please elaborate and what factors do you consider.	times the market places too much emphasis on nuclear risk, but analyst believes most investors generally see nuclear as higher risk. Regulators must deal with reality of supply mix – can't only have renewable energy; nuclear is reliable source of baseload supply at relatively low variable cost; if OEB wanted to get rid of nuclear, rate pressure would be significant (in province that already has rate pressure). (Canadian equity analyst) • Analyst views it as more risky. Has heard of investors with investment policy statements that restrict any exposure to nuclear energy, period. The key issues are mainly construction (common for cost overruns), operating (more unplanned outages), and disposal of fuel along with general negative sentiment around the technology following nuclear disasters in Japan. Analyst covers a company that owns and operates nuclear power facilities as well as pipelines – for nuclear they target a 9% unlevered return whereas for pipelines it's 7-8% to account for the differences in risk. (Canadian equity analyst) • Yes, nuclear has higher safety requirements and environmental risk, more risky than other types of generation; nuclear risk is company specific even with state legislation to support nuclear capital cost recovery – does not always provide protection depending on circumstances of company. (North American credit analyst)
Regulated utilities in Canada and Ontario typically have allowed equity ratios below those authorized for US utilities. Do you believe these differentials are justified by actual	• Already covered above. (Canadian equity analyst) • Cost of capital parameters are function of where you are; lack of movement in ROEs is implicit admission that Canadian ROEs are already low; US ROEs have trended lower. Equity thickness gap has not narrowed between Canada and US – analyst would prefer that equity ratio gap be lowered; harder for Canadian regulators to raise ROE than to raise equity ratio because ROE is more transparent to public; also credit rating agencies tend to prefer lower debt ratios. (Canadian equity analyst) • I don't think there is a material difference in business risk between Canadian and U.S. utilities. The factors we would look at is the cost competitiveness of the supply (i.e. gas or electricity vs. other alternatives), the ability to recover costs, the counterparty/customer concentration, and

Question	Responses
or perceived differences in business or regulatory risk in Canada or Ontario as compared with the US? Please elaborate.	stranded asset risk (which might increasingly become more of a growing issue for gas utilities than electric utilities esp. in the U.S. NE and California). (Canadian equity analyst) • Comes down to cash flow support and timely cost recovery – prefer rider recovery over deferrals – is company able to recover expenses and meet obligations on timely basis – lower debt level tends to bolster financial measures and credit quality – many Canadian utilities were govt owned – does that drive some of difference? (North American credit analyst) • As ROEs have come down in U.S., equity thickness has been sticky. Reductions in shareholder returns across the board. What about the analysis of what's best for customers? Tend to set equity ratios where you can do something that makes sense for customers and the utility. Want to keep an high credit rating level, for example, and providing regulatory support for metrics to support it. TX – firm's ratings change based on Staff recommendation. Investors ask: "How's this thing investment grade at 40% equity"? No default in CAN. Political interference? OPG is probably somewhere in the middle – cost disallowances. Don't expect OPG to have political interference where, for example, an entire regulatory asset is written off to keep rates lower. (North American credit analyst)

CME Interrogatory #25

Interrogatory

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

Concentric stated "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."

(a) Please confirm whether OPG's actual risks have changed as a result of the nuclear projects elsewhere, rather than simply the 'perceived risk.'
(b) With respect to budget and schedule issues, has Concentric reviewed the evidence in this proceeding or otherwise submitted to the board regarding the DRP in order to examine whether OPG may encounter any of the same difficulties as the Vogtle and Summer plant projects?

Response

Response prepared by Concentric Energy Advisors

(a) While there are certainly events in the nuclear industry that, while occurring at one or a few plants (e.g., such as the earthquake and tsunami that affected Japan on March 11, 2011, causing significant damage to the Fukushima Daiichi nuclear complex), reverberate and impact operations of the worldwide nuclear fleet, in the statement cited in the interrogatory Concentric is focused on investor perceptions, and specifically the incorporation of available information into investors' assessments of risk. As such, while the events described in the interrogatory did not change OPG's actual risks, they rather made investors more keenly aware of the risks involved in large nuclear construction projects, raising the perceived risk and cost of capital for such projects.

(b) As described on page 37 of Concentric's report, Concentric is aware that OPG has carefully planned the refurbishment of the three remaining Darlington units, including applying lessons learned from the Unit 2 refurbishment. Furthermore, the DRP and the construction of new nuclear facilities in the southeast U.S. are different projects, and, as such, Concentric would not expect the same exact challenges at

Vogtle and Summer to be experienced on the DRP. However, risks related to challenges of the same nature faced at Vogtle and Summer (e.g., cost and schedule overruns due to first-of-a-kind projects, financial troubles and vendors, and issues that befall many megaprojects regardless of technology) are inherently present at the DRP. Concentric is aware that OPG takes proactive steps to mitigate those risks, but it cannot eliminate them.

Energy Probe Interrogatory #7

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, Pages 20-21

Preamble: The Concentric Report states that "Equity analysts have also indicated that they view the regulatory environment in Canada in Canada and the U.S. as being similar…" (p.20)

Indeed, the Concentric Report also states that "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…" (p.22)

a) On a plain reading, doesn't this evidence suggest that U.S. equity ratios are too high in light of the recent U.S. regulatory improvements when compared to the equity ratios of Canadian utilities?

b) Are U.S. regulators moving in the direction of lower equity ratios for U.S. utilities? If not, why not?

Response

Response prepared by Concentric Energy Advisors.

a) No, Concentric would not reach that conclusion. Regulatory support is a key factor in credit ratings and the ability to raise both debt and equity capital on reasonable terms. Furthermore, the majority of U.S. regulators establish the ratemaking equity ratio with reference to utilities' actual equity ratios. Significantly raising the debt levels at U.S. utilities would have substantial credit impacts and lead to an overall increase in the cost of capital.

b) Concentric is not aware of concerns expressed by U.S. regulators that equity ratios for U.S. utilities are too high, nor have we seen a downward trend. In our experience, U.S. regulators base their decisions on allowed equity ratios on several factors, including: actual capital structures maintained by the utility; comparisons to similar utilities, typically within a range; credit rating considerations and financial metrics; and overall assessments of risk for the subject utility. Please see Attachment 1 EP-7 for a summary of U.S. rate case statistics, including equity ratios, over time.

Rate Case Statistics

State : Total US
Frequency : Annual
Date Range: 15 Years
Service Type : Electric
Metric Type : Mean
Chart Items : Common Equity to Total Capital, Return on Equity

Data

Electric

DATE	STATE	RETURN ON EQUITY (%)	RETURN ON CAPITAL (%)	RATE CHANGE/ REVENUE (%)	ORIGINAL COST RATE BASE ($000)	RATE CHANGE AMOUNT ($000)	RATE CASE RETURN ORIGINAL COST (%)	COMMON EQUITY TO TOTAL CAPITAL (%)
2020	Total US	9.44	NA	3.38	3,591,367	32,351	6.83	49.69
2019	Total US	9.66	NA	2.80	2,758,613	26,368	6.97	49.94
2018	Total US	9.60	7.41	3.50	2,681,059	28,065	6.93	49.02
2017	Total US	9.74	7.30	4.18	3,276,094	35,008	7.18	48.90
2016	Total US	9.77	7.54	5.55	1,458,542	40,105	7.28	48.91
2015	Total US	9.84	7.40	4.36	3,542,335	37,042	7.35	49.23
2014	Total US	9.91	7.68	7.48	2,478,234	40,268	7.60	50.28
2013	Total US	10.03	7.67	6.37	2,239,363	54,567	7.66	49.25
2012	Total US	10.17	7.85	5.18	2,405,813	44,647	7.95	50.69
2011	Total US	10.29	8.13	6.40	2,193,600	46,340	8.00	48.26
2010	Total US	10.37	NA	6.78	2,409,144	63,101	8.01	48.63
2009	Total US	10.52	8.08	6.98	2,742,503	72,271	8.28	48.36
2008	Total US	10.41	8.47	7.43	2,024,952	64,163	8.21	47.94
2007	Total US	10.30	8.69	5.24	1,941,945	32,690	8.18	47.88
2006	Total US	10.32	8.94	5.98	1,540,519	33,796	8.32	48.54

Chart

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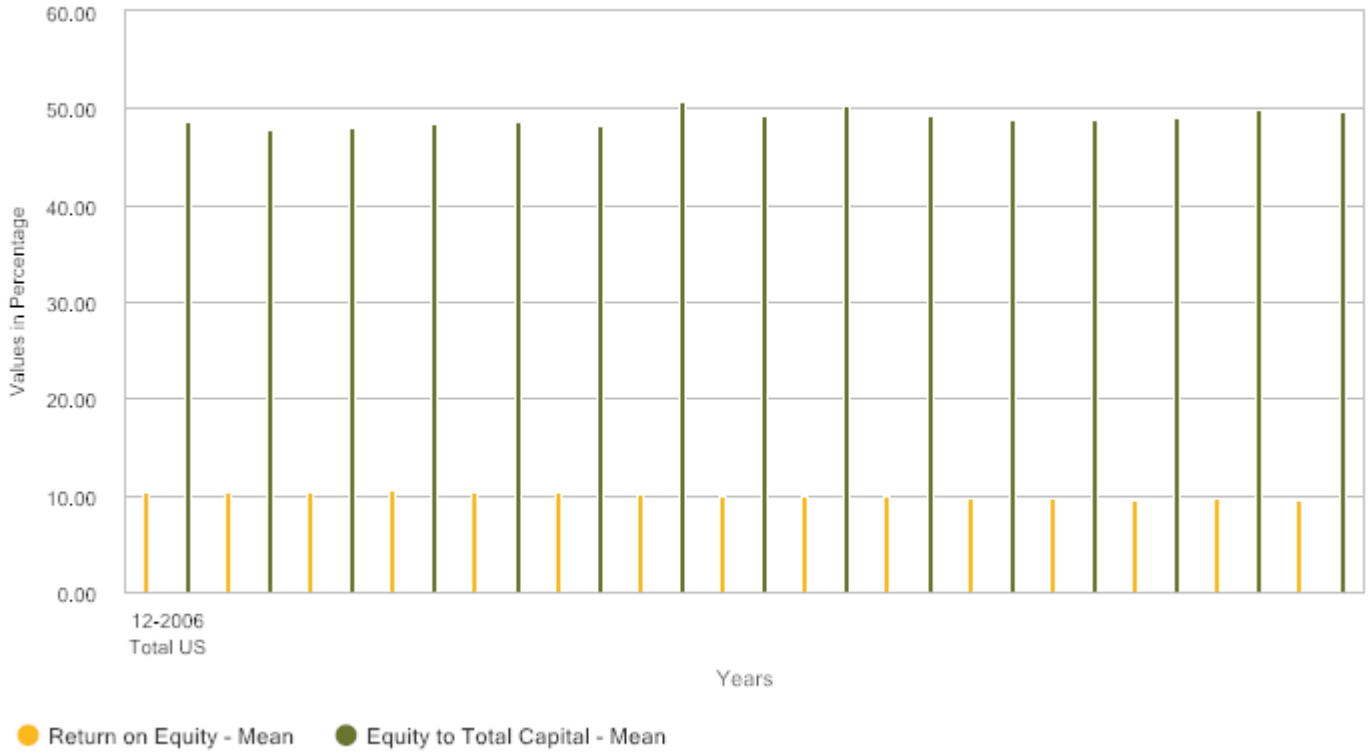
Rate Case Statistics for Electric

From 2/16/2006 to 2/16/2021



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Energy Probe Interrogatory #8

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, Page 34

Preamble: The Concentric Report states that "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." (p.34)

a) Is it Concentric's view that OPG's Custom IR framework for nuclear is itself a source of risk that requires a higher equity ratio for that business?
b) Is it also Concentric's view that an IR scheme (whether "custom" or fully-implemented) as contemplated by the Board would also be a source of risk to OPG's hydroelectric business?

c) In principle, does incentive regulation aim to provide investors with returns associated with the Fair Return Standard? If not, then why should regulators ever move from conventional rate-base/ROE regulation to incentive regulation?

Response

Response prepared by Concentric Energy Advisors

a) There are elements of OPG's IR framework that create risks atypical of regulated companies operating nuclear generation facilities in North America. As noted by Concentric on page 34 of its report, "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." This risk would support an equity ratio toward the higher end of the proxy group, but Concentric has conservatively recommended an equity ratio at the lower end, so it is not fully factored into the recommendation.

b) In general, IR schemes are designed to delink the relationship between allowed revenues and costs. It is Concentric's view that IR plans are therefore generally considered by investors to be riskier than cost of service regulation.

c) In Concentric's experience, IR plans are not designed to provide returns that meet the fair return standard. It is the cost of capital that is set to meet the fair return standard, and the form of ratemaking (incentive regulation, cost of service or a hybrid (e.g., custom IR) is established to allow the utility a reasonable opportunity to earn its allowed return, and may also contain incentives or penalties based on performance. Regulators may implement performance-based ratemaking to incentivize performance improvements for the benefits of customers and for the prospects of administrative efficiency. Other public policy goals may also be integrated (e.g., decarbonization, or increased energy efficiency). These goals cannot, however, compromise the utility's opportunity to earn a fair return.

Energy Probe Interrogatory #9

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, Figure 12, Page 59

Preamble: "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."

a) Please provide a quantitative version of Figure 12 showing Generation and Rate Base for Nuclear Portion broken out for PNGS and DNGS.

b) Concentric suggests (page 8)
"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."

Specifically discuss why the consolidation of nuclear assets at Darlington does not reduce risk since OPG is moving from two stations to a single station starting in 2025?

Response

a) The Darlington NGS and Pickering NGS production values are provided in Ex. E2-1-1 Table 1. These are the same values provided in Figure 12 of the Concentric Report.

The rate base numbers included in Figure 12 of the Concentric Report are provided in detail in OPG's Rate Base exhibits (Exhibit B). A summary of those amounts is included in Attachment 1, Table 1.

b) Response prepared by Concentric Energy Advisors

Please see Exhibit C1-1-1, Attachment 1, at 47, where it states "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.

Numbers may not add due to rounding.

Table 1
Prescribed Facility Rate Base - Nuclear ($M)

Line No.	Rate Base Item	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
1	Darlington NGS[1]	911.9	1,112.2	1,358.7	1,522.3	1,721.7	1,943.7	2,305.9	2,668.0	2,937.1	3,200.9
2	Darlington Refurbishment Program[1]	594.6	693.6	684.7	3,402.3	5,246.7	4,979.4	4,815.2	7,112.6	8,188.5	8,849.1
3	Heavy Water Storage Facility (D2O)[1]	171.3	166.5	188.0	478.9	470.9	455.9	441.0	426.0	411.0	396.1
4	Pickering NGS[1]	616.2	598.2	544.2	478.1	388.7	260.8	152.9	76.8	38.7	38.7
5	Operations and Project Support[1]	81.8	102.4	99.1	96.8	128.0	150.3	212.4	214.5	210.9	199.5
6	Asset Retirement Costs[1]	505.1	570.6	488.5	406.3	324.1	242.0	175.7	125.1	98.1	94.6
7	Net Plant[1]	2,881.0	3,243.6	3,363.1	6,384.7	8,280.1	8,032.1	8,103.1	10,623.1	11,884.4	12,778.9
8	Cash Working Capital[2]	11.5	2.3	(4.1)	(37.8)	(37.8)	(37.8)	(37.8)	(37.8)	(37.8)	(37.8)
9	Fuel Inventory[2]	270.6	259.0	224.7	190.9	190.6	208.7	209.8	189.8	185.9	178.5
10	Materials & Supplies[2]	446.4	449.6	463.6	494.8	508.7	517.3	513.5	485.6	435.9	392.5
11	Total Rate Base	3,609.5	3,954.4	4,047.2	7,032.6	8,941.8	8,720.4	8,788.7	11,260.7	12,468.5	13,312.0

Notes:
1 From Ex. B3-1-1, Table 1 and 2.
2 From Ex. B3-5-1, Table 1 and 2.

Energy Probe Interrogatory #10

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, Page 61

Preamble: In EB-2016-0152, the OEB found that "capital structure should be reviewed only when there is a significant change in *financial*, business or corporate fundamentals."

a) Please describe what has changed in the last 5 years to affect the OPG deemed equity ratio.

b) Please list and rank/weight the factors affecting OPG capital structure in 2015 and 2020.

c) Is the reduction in Long Term Debt rates a positive or negative factor in financial risk. Please discuss.

d) Is the change in the Ontario Provincial Debt Rating a factor? (+/-)

e) Please provide and comment on the OPG FFO/Debt ratio and CFO/debt ratio and how these will change with an increase on deemed equity.

Response

Response prepared by Concentric Energy Advisors

a) Please see Concentric's report, and specifically the discussion of changes to OPG's business and financial risk profiles, at pages 29-59.

b) See the response to part (a), and also L-C1-01-Staff-43.

c) For a regulated utility, which reflects its cost of borrowing in rates, a reduction in long-term interest rates would likely have a neutral effect. To the extent there is a significant lag between when the utility borrows at lower rates and when those costs are reflected in rates, a reduction in borrowing rates could increase near-term cash flows, although the reduction in borrowing costs could be offset by increased borrowings and/or offsetting changes to cash flows driven by other risks.

d) While a change in Ontario's credit rating could impact OPG's credit rating, Concentric analyzed OPG on a stand-alone basis.

e) All else equal, an increase in deemed equity ratio would increase OPG's cash flows and increase its FFO/Debt and CFO/Debt ratios.

Energy Probe Interrogatory #11

Interrogatory

Reference:
Exhibit C1, Tab1, Schedule 1, Attachment 1, Page 70, Figure 16, Concentric Proxy Group

a) Why is Bruce NGS not in the proxy group?

b) How many of the Concentric proxy group meet the three criteria on pages 66/67?

c) How many are predominately generators (list re Fig 20)?

d) How many operate in an RTO/ISO environment? (list)?

e) How many have nuclear generation (list)?

f) How many have risk-reducing deferral and variance accounts. (list)?

g) Why are generators more risky than transmitters and combined companies?

h) Please compare your assessment of OPG financial risk to Bruce NGS on a similar basis.

Response

Response prepared by Concentric Energy Advisors

a. Concentric assumes this question is referring to Bruce Power, L.P. ("Bruce Power"), the Ontario-based private company involved in the production of nuclear power. Concentric did not include Bruce Power in its proxy group primarily because: (1) Bruce Power is not publicly traded, (2) Bruce Power is not a regulated utility, and (3) Concentric does not have Bruce Power's historical financial statements.

b. All seventeen of the US companies included in the proxy group meet the screening criteria listed on pages 63-65 of the Concentric Report. As described on page 65-66, none of the publicly-traded Canadian companies that Concentric reviewed met all of our screening criteria. However, we included Emera, Fortis, and Algonquin to broaden the proxy group to include at least a minimal number of Canadian utilities.

c. As described on pages 63-64 of the Concentric Report, we applied multiple screening criteria to ensure that each company in our proxy group owns regulated generation assets that are included in rate base, and specifically regulated nuclear and/or hydroelectric generation assets. However, unlike OPG, none of the companies in the Concentric proxy group are "predominantly" generators. Please see Figure 19 on page 72 of the Concentric Report for the proportion of generation assets versus transmission and distribution assets for each company in the Concentric proxy group.

d. The following companies in Concentric's proxy group own one or more generation assets (regulated or unregulated) in an RTO/ISO environment according to S&P Global Market Intelligence:
- ALLETE, Inc.
- Ameren Corporation
- American Electric Power Co., Inc.
- Duke Energy Corporation
- Edison International
- El Paso Electric Company
- Entergy Corporation
- FirstEnergy Corporation
- Evergy, Inc.
- IDACORP, Inc.
- NextEra Energy, Inc.
- Pinnacle West Capital Corporation
- PNM Resources, Inc.
- Southern Company
- Xcel Energy, Inc.
- Algonquin Power & Utilities Corp
- Emera, Inc.
- Fortis Inc.

e. As listed in Exhibit 1 of the Concentric Report, 12 of the companies in Concentric's proxy group own regulated nuclear generation capacity.

f. Please see Exhibit 5.1 of the Concentric Report for an analysis of the risk-reducing deferral and variance accounts available to the companies in Concentric's proxy group.

g. The risk of electric generation relative to electric transmission and distribution is discussed throughout the Concentric report. For example, on page 63, we note that Moody's has stated it views "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.

h. Concentric is unable to compare the financial risk of OPG and Bruce Power for the reasons described in the response to part (a).

Energy Probe Interrogatory #12

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 2, pages 1 and 2

Please explain the advantages, disadvantages, and restrictions on the use of Green Bonds for Medium Term Notes.

Response

Advantages of Green Bonds include growing demand as investors are pursuing socially responsible investment opportunities and have expressed a strong interest in Green Bonds. Disadvantages of Green Bonds include restrictions on the use of proceeds and additional reporting and audit requirements. Green Bond proceeds can be allocated only to eligible projects meeting the criteria as defined in OPG's Green Bond Framework, such as investments that help to supply energy from renewable sources, including hydroelectric generation.

Energy Probe Interrogatory #13

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 2, Tables 7a.8a,9a.

Preamble: "Interest Rates for new LT debt issues are forecast to increase from 2021-2025."

c) Please discuss why OPG could not issue the 2021-2024 debt on an accelerated schedule?

d) What would be the benefits/costs of such an approach?

e) What is the GOC and OPG spread forecast for the Issue 39?

Response

a) and b)

OPG is not currently planning to pre-fund its anticipated 2021-2024 debt requirements for several reasons. First, OPG would incur incremental carrying costs for non-productive cash, which would reduce its corporate net income. Second, the higher debt load would negatively affect OPG's credit metrics in the very period that the metrics are already under pressure. Third, cash requirements cannot be predicted with certainty; they are the net result of many elements that are inherently variable both in amount and timing. As a result, it is not typical for companies to pre-fund their operating needs more than 1 to 2 years in advance.

Potential benefits of pre-funding debt can include funding certainty and fixing the interest cost. OPG does not currently foresee any significant risk to future funding availability. OPG also does not expect that fixing the interest rate at current levels will necessarily yield a lower cost compared to borrowing in the future. To make such a judgement, one would need to hold the view that the market is materially underestimating the extent of future interest rate increases. OPG currently does not have a basis for such a view to carry out pre-funding for the 2021-2024 period.

c) An Issue 39 was forecasted in Q1 2020 in EB-2016-0152 and was based on GOC of 3.32% and Spread of 1.61%, for an effective rate of 4.93% (EB-2016-0152, Ex. C1-1-2, Table 10, line 14).

LPMA Interrogatory #7

Interrogatory

Ref: Exhibit C1, Tab 1, Sch. 1 & Exhibit I1, Tab 1, Sch. 1

Please provide a table that shows the forecast revenue deficiency for each of 2022 through 2026, as shown on page 2 of Exhibit I1, Tab 1, Schedule 1 along with the forecast revenue deficiency for each of 2022 through 2026 if the return on equity shown in Tables 1 through 5 in Exhibit C1, Tab 1, Schedule 1 is increased by 100 basis points (i.e. from 8.34% to 9.34%).

Response

The table is provided as Attachment 1.

Witness Panel: Finance and D&V Accounts

Privileged and confidential. Prepared in contemplation of litigation.

Numbers may not add due to rounding.

Table 1
Revenue Requirement Impact of 9.34% ROE ($M)

Line No.	Description	2022	2023	2024	2025	2026
		(a)	(b)	(c)	(d)	(e)
1	**Nuclear Rate Base**[1]	8,646.8	8,788.7	11,260.7	12,468.5	13,312.0
2	**ROE**[2]	8.34%	8.34%	8.34%	8.34%	8.34%
3	**ROE increased by 100 basis points**	9.34%	9.34%	9.34%	9.34%	9.34%
4	**Cost of Debt**[2]	3.63%	3.51%	3.64%	3.68%	3.69%
5	**Deemed Equity (Proposed)**[2]	50%	50%	50%	50%	50%
6	**Deemed Debt (Proposed)**[2]	50%	50%	50%	50%	50%
7	**Proposed WACC**[3]	6.0%	5.9%	6.0%	6.0%	6.0%
8	**WACC with ROE increased by 100 basis points**[4]	6.5%	6.4%	6.5%	6.5%	6.5%
9	**Revenue Requirement (Proposed)**[5]	637.7	643.1	831.1	922.9	985.6
10	**Revenue Requirement (ROE Increased by 100 basis points)**[6]	695.3	701.7	906.2	1006.0	1074.3
11	**Revenue Requirement Impact of 100 basis point increase on ROE**[6]	**57.6**	**58.6**	**75.1**	**83.1**	**88.7**
12	**Revenue Deficiency (Proposed)**[7]	633.3	775.6	657.2	616.6	621.4
13	**Revenues Deficiency (ROE increased by 100 basis points)**[8]	575.7	717.0	582.1	533.4	532.6

Notes

1 Ex. B1-1-1 Table 2, line 7 minus the Adjustment for Lesser of UNL or ARC from Ex. C1-1-1 Tables 1-5, line 7
2 C1-1-1 Tables 1-5
3 Calculated as: (Line 2 X Line 5) + (Line 4 X Line 6)
4 Calculated as: (Line 3 X Line 5) + (Line 4 X Line 6)
5 (Line 1 x Line 7) + (Line 1 x Line 2 x Line 5) x (tax rate / 1- tax rate), where the tax rate is 25%
6 (Line 1 x Line 8) + (Line 1 x Line 3 x Line 5) x (tax rate / 1- tax rate), where the tax rate is 25%
7 (Line 10 - Line 9)
8 Ex. I1-1-1 Table 3
9 (Line 12 - Line 11)

LPMA Interrogatory #8

Interrogatory

Ref: Exhibit C1, Tab 1, Sch. 1 & Exhibit I1, Tab 1, Sch. 1

Please provide a table that shows the forecast revenue deficiency for each of 2022 through 2026, as shown on page 2 of Exhibit I1, Tab 1, Schedule 1 along with the forecast revenue deficiency for each of 2022 through 2026 if the common equity component of rate base shown in Tables 1 through 5 in Exhibit C1, Tab 1, Schedule 1 was maintained at 45% (i.e. down from 50%).

Response

Chart 1: Revenue Requirement Deficiency ($M)

Line	Description	2022	2023	2024	2025	2026
1	OPG Proposed Revenue Requirement Deficiency[1]	633.3	775.6	657.2	616.6	621.4
2	Revenue Requirement Impact of 45% Common Equity[2]	(32.4)	(33.4)	(42.1)	(46.4)	(49.5)
3	Revenue Requirement Deficiency at 45% Common Equity[3]	600.9	742.2	615.1	570.2	571.9

[1] Ex. I1-1-1, Table 3.
[2] Ex. C1-01-CCC-027, Attachment 1, p. 6.
[3] (line 1 + line 2).

Witness Panel: Finance and D&V Accounts

SEC Interrogatory #20

Interrogatory

Reference: C1-1-1, Attachment 1, p.4, 6, 33, 40

Concentric forecasts that OPG's execution risk from the Darlington Refurbishment Project will increase in the IRM term. However, OPG advises that it has successfully completed the first unit, plus common elements, on time and on budget. Why does the successful completion of more than 35% of the DRP not result in a reduction in execution risk, rather than an increase in execution risk?

Response

Response prepared by Concentric Energy Advisors

As discussed in Ex. C1-1-1, Attachment 1, p. 37, OPG has successfully completed the Darlington Refurbishment Project ("DRP") refurbishment of Unit 2 in 2020, which has been positively noted by the credit rating agencies. The credit rating agencies, however, continue to highlight the elevated level of execution risk related to the DRP (and, if the Unit 2 refurbishment had not gone well, the risk would be higher still). The DRP is entering a period of acute execution risk beyond what is has experienced during the prior rate setting period for four main reasons, as discussed in Ex. C1-1-1, Attachment 1, pp. 37-40. In summary, those reasons are:

1. The fact that three Darlington units will be offline during the upcoming rate setting period with overlapping refurbishments, and Bruce Power will also have multiple units offline placing high demand on labor resources and vendors;
2. OPG plans to execute new scope during the refurbishment of Units 3, 1 and 4;
3. OPG is at increased risk of vendor default (e.g., SNC Lavalin Nuclear Inc. was downgraded to a sub-investment grade credit rating in August 2019) ; and
4. The ongoing COVID-19 pandemic adds additional risk to the program including as it relates to productivity risk and resource availability risk.

SEC Interrogatory #21

Interrogatory

Reference: C1-1-1, Attachment 1, p.5, 6, 31

Please confirm the expert's opinion that the current OEB formula for establishing ROE is no longer appropriate, as it is adjusting ROE downward when in the expert's view ROE should actually be increasing.

Response

Response prepared by Concentric Energy Advisors

Concentric has not evaluated or expressed an opinion on whether the OEB's formula for establishing ROEs is currently appropriate. Concentric observed in its report (at Ex. C1-1-1 Attachment 1, p. 28) that there is evidence that the cost of equity for regulated utilities has increased, while the OEB's formula produced a reduction in ROE from 8.52% to 8.34% for the 2021 rate year. Concentric further observed that this places the allowed ROE in Ontario below that of any other North American regulatory jurisdiction and negatively affects OPG's credit metrics.[1] As a point of clarification, one jurisdiction is lower, being for a government owned utility, Hydro Quebec, which has substantial lower risk transmission and distribution assets (and no regulated power production).

[1] Concentric first provided similar data to the OEB in 2009 in response to the Board's consultation on the then-existing formula (see the Cost of Capital in Current Economic and Financial Market Conditions, Ontario Energy Board EB-2009-0084, written submission of Enbridge Gas Distribution Inc., April 17, 2009, PDF 12).

SEC Interrogatory #22

Interrogatory

Reference: C1-1-1, Attachment 1, p.5, 23, 25

Please provide a complete list of the "equity and credit analysts" interviewed, and in each case provide either a CV or a link to a bio on their employer's website.

Response

Response provided by Concentric Energy Advisors.

Please see in Ex. C1-1-1, Attachment 1, p. 22, footnote 37, for a list of survey participants and the firms by which they are employed. In each case, the survey participants were equity or credit analysts who cover the North American utility industry. To Concentric's knowledge, the analysts' firms do not provide CVs or bios for their analysts.

SEC Interrogatory #23

Interrogatory

Reference: C1-1-1, Attachment 1, p.5, 23, 26

Please provide citations since 2017 (other than the Scotiabank report cited) of academic or technical papers showing "the investment community's view is that any regulatory risk differential between the countries has narrowed significantly, if not disappeared".

Response

Response prepared by Concentric Energy Advisors.

Standard and Poor's ("S&P") periodically assesses each regulatory jurisdiction in the U.S. and Canada with a rated utility or where a rated utility operates. S&P's assessment ranges from "Credit Supportive" to "Most Credit Supportive". S&P explains that "[t]he presence of utility regulation, no matter where in the spectrum of our assessments, strengthens the business risk profile and generally support utility ratings." The most recent S&P report was published in June 2020 and is provided as Attachment 1 to this response. This report indicates that Ontario is in the "Most Credit Supportive" S&P category along with nine other U.S. jurisdictions including the FERC and four other Canadian provinces. S&P also ranks 16 U.S. states and one additional Canadian province as "Highly Credit Supportive", which is the second best ranking on the scale. These S&P rankings of the regulatory jurisdictions in Canada and the U.S. provide additional support for the view that investors consider differences in regulatory risk between Canada and the U.S. as minimal.

S&P Global
Ratings

RatingsDirect®

U.S. And Canadian Utility Regulatory Updates And Insights: June 2020

June 8, 2020

Key Takeaways

- S&P Global Ratings periodically assesses each regulatory jurisdiction in the U.S. and Canada with a rated utility or where a rated entity operates.
- These assessments--with categories from "credit supportive" to "most credit supportive"--provide information for reference in determining the regulatory risk of a regulated utility or holding company with more than one utility. We made no changes since our last report, but examine developments in several jurisdictions.
- We base our analysis on quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.
- The presence of utility regulation, no matter where in the spectrum of our assessments, strengthens the business risk profile and generally supports utility ratings.

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S&P Global Ratings conducts periodic assessments of each regulatory jurisdiction in the U.S. and Canada where a rated utility operates as a reference when determining a utility's regulatory advantage or regulatory risk. Regulatory advantage is a heavily weighted factor in our analysis of a regulated utility's business risk profile.

Our analysis covers quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation. (See "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, for more details on each category.)

Sorting Through Regulatory Jurisdictions In The U.S. And Canada

We updated our assessments of regulatory jurisdictions since our commentary "U.S. And Canadian Regulatory Jurisdiction Updates And Insights: November 2019," published Nov. 4, 2019. Our assessments of U.S. jurisdictions' and Canadian provinces' approaches to regulation over the past several months are unchanged. Here, we provide our current snapshot of each regulatory jurisdiction (Table 1, Charts 1 and 2). We group the jurisdictions by the quantitative and qualitative

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-SEC-023
Attachment 1
Page 2 of 10

factors and collective opinions expressed in the regulatory advantage determinations made in rating committees for the approximately 225 U.S. and 30 Canadian utilities we rate.

The categories indicate an important point regarding utility regulation and its effect on ratings: They are denoted credit supportive to one degree or another, as all utility regulation sustains credit quality when compared with corporate and infrastructure ratings. The presence of regulators, no matter where in the spectrum of our assessments, reduces business risk and generally supports utility ratings. We describe all these jurisdictions in a range from credit supportive to most credit supportive, and these vary only in degree rather than in kind.

Assessing U.S. And Canadian Regulatory Jurisdictions

Table 1

Regulatory Jurisdictions For Utilities Among U.S. States And Canadian Provinces

Credit supportive	More credit supportive	Very credit supportive	Highly credit supportive	Most credit supportive
Hawaii	Alaska	Connecticut	Arkansas	Alabama
Mississippi	Arizona	Delaware	Georgia	Alberta
New Mexico	California	Idaho	Indiana	British Columbia
Prince Edward Island	District of Columbia	Illinois	Kansas	Colorado
	Maryland	Missouri	Louisiana	FERC (electric)
	Montana	Nebraska	Maine	Florida
	New Jersey	Nevada	Massachusetts	Iowa
	Oklahoma	New Orleans	Minnesota	Kentucky
	South Carolina	New York	New Hampshire	Michigan
	Washington	Ohio	Newfoundland & Labrador	North Carolina
		Rhode Island	North Dakota	Nova Scotia
		South Dakota	Oregon	Ontario
		Texas	Pennsylvania	Quebec
		Vermont	Tennessee	Wisconsin
		West Virginia	Texas RRC	
		Wyoming	Utah	
			Virginia	

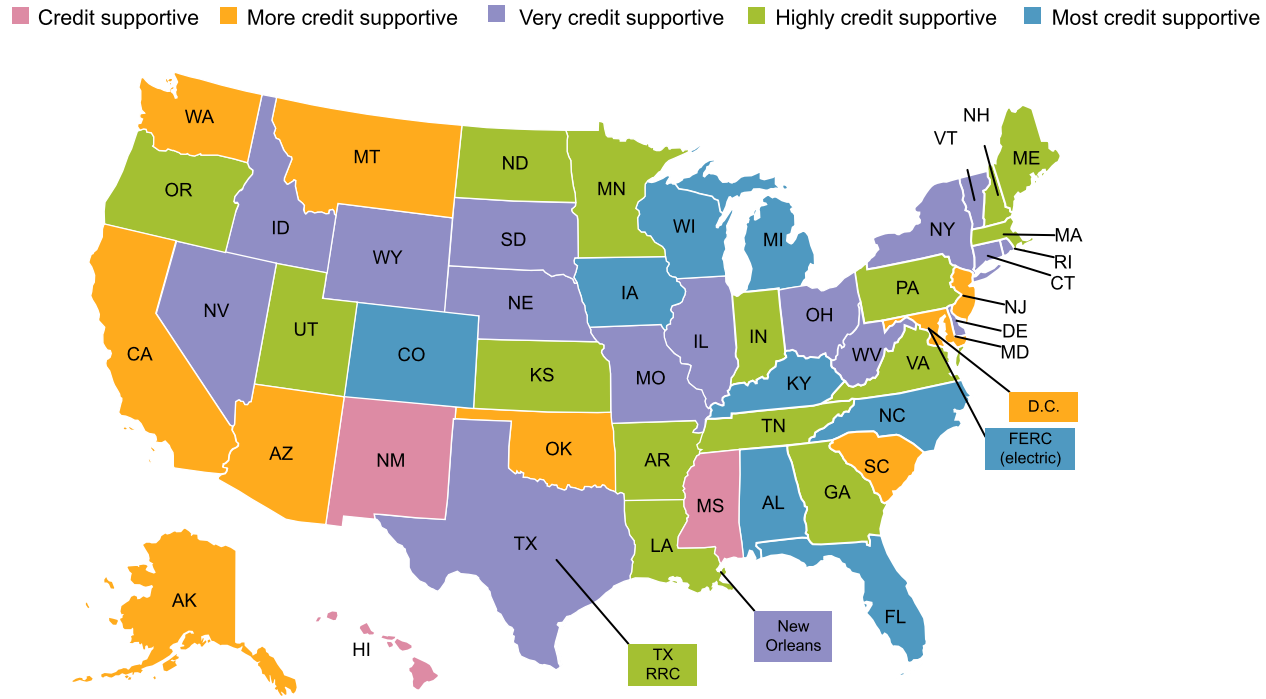
FERC--U.S. Federal Energy Regulatory Commission. RRC--Railroad Commission of Texas.

Mapping Regulatory Jurisdictions

For jurisdictions assessed in these maps (Charts 1 and 2), colors delineate our assessments of credit supportiveness. (We do not have assessments on some Canadian provinces where we don't rate any utilities.) The assessments offer some scale and detail in our thinking regarding the rules and implementation of regulation. Often they simply designate a stable jurisdiction slightly better or worse than its closest peers in credit quality.

Chart 1

Regulatory Assessment By State



FERC—Federal Energy Regulatory Commission. RRC—Railroad Commission of Texas. Data as of June 2020.

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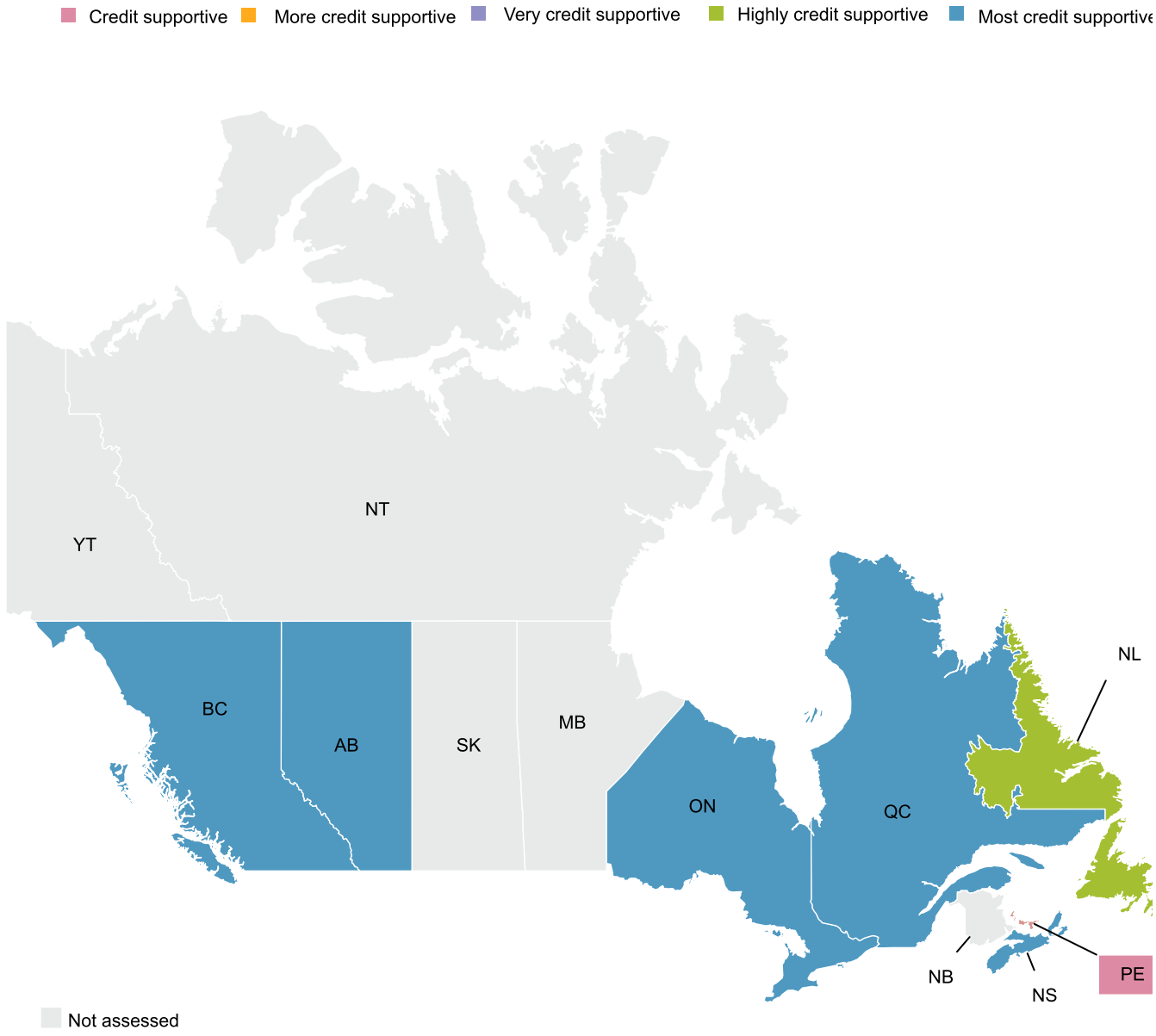
Chart 2

Regulatory Assessment By Canadian Province/Territory



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Notable Topics Throughout North America

Although our biannual review found no material events that would change a jurisdictional assessment amid the COVID-19 pandemic, there have been an unprecedented number of regulatory actions with respect to cost recovery and bad debt collection moratoriums ("Regulatory Responses To COVID-19 Are Key To Utilities' Credit Prospects", published May 20, 2020). In

addition, other notable developments have occurred in several jurisdictions.

Alberta

Compared to our assessment in November, the Alberta regulatory construct is weakening as regulatory lag has not improved. In addition, utilities are continually exposed to the risk of absorbing the undepreciated capital cost of stranded assets due to extraordinary retirement. Furthermore, the recent regulatory decision by the Alberta Utilities Commission regarding the Alberta Electric System Operator's customer contribution policy, under which requiring distribution operators to transfer transmission related investments to transmission operators at net book value, somewhat calls into question the regulatory framework's consistency.

FERC Electric

Recent U.S. Federal Energy Regulatory Commission (FERC) rulings on Midcontinent Independent System Operator (MISO) transmission owners' authorized return on equity (ROE) indicate inconsistency in how ROE decisions could be applied toward New England transmission owners' ROEs. Specifically, in late 2018, FERC proposed using a new ROE calculation method that focused on four factors. However, in late 2019, FERC did not use that methodology to establish the new ROE for MISO transmission owners, instead using a method that relied on two factors. Furthermore, FERC further revised the methodology in May 2020 by adding a third approach to calculate transmission owner ROEs. It was marginally favorable for MISO transmission owners compared to the two-factor approach, but resulted in a slight base ROE reduction.

Although there are inconsistencies regarding ROEs for electric transmission owners, we continue to consider FERC regulation toward electric transmission as one of the most credit supportive.

Hawaii

The state is undergoing regulatory reform, and the Hawaii Public Utilities Commission (HPUC) is proceeding with a performance-based regulation (PBR) framework. HPUC plans to finalize the implementation details by the end of 2020. The proposal includes a five-year rate plan with an indexed annual revenue adjustment mechanism, coupled with existing capital recovery mechanisms in between rate cases. We expect this will improve the timeliness of both capital and operating cost recovery for utilities that could lead to improved profitability.

In addition, an earnings-sharing mechanism (ESM) and various performance incentive mechanisms (PIMs) are included. The proposed ESM shares excess earnings with customers and protects the utilities from extreme financial shortfalls. PIMs may provide potential earnings to a utility should it meet certain performance targets. Overall, we expect the new PBR framework will lead to more regulatory predictability and cash flow stability for utilities in Hawaii, including Hawaiian Electric Industries Inc.

Massachusetts

Due to the state regulatory commission's recent rate decision for utility Massachusetts Electric Co. in late 2019, we believe the regulatory environment is gradually improving. The Mass Electric rate case decision was the second major case that included a PBR mechanism, the first being NSTAR Electric Co. Such mechanisms provide for a more predictable formulaic rate setting construct that accounts for utilities' capital and operational spending, inflation over a five-year

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-SEC-023
Attachment 1
Page 6 of 10

period, and a decoupling mechanism that provides downside protection irrespective of sales volume declines.

NSTAR Gas Co. recently filed for a similar PBR mechanism in their gas distribution rate case, and we are monitoring this development. Overall, even with our view of gradual improvement, we believe there could be regulatory lag since the state uses historical test years when setting rates.

Mississippi

We continue to monitor the pending regulatory commission decision on Mississippi Power Co.'s (MPC) reserve margin plan (RMP), a request by the regulator to develop alternatives to lower its reserve margin. This plan could accelerate retirements for some of MPC's coal-fired power plants by 2022. We continue to monitor this proceeding to determine how the rate recovery of remaining book value of retired assets will be addressed.

Nevada

Following a legislative initiative in 2019, the Public Utilities Commission of Nevada (PUCN) initiated a proceeding and has conducted workshops regarding the options around alternative ratemaking plans that could include formula rates, decoupling, earnings sharing, and multiyear rate plans. In April 2020, PUCN released the first report that outlines efforts regarding potential alternative ratemaking mechanisms for Nevada's electric utilities. Ultimately a draft proposal may be issued in 2021 with regulations adopted after reviewing feedback from workshop participants. PUCN is evaluating whether alternative ratemaking would provide better incentives than traditional cost-of-service ratemaking for NV Energy Inc.'s regulated utilities, Nevada Power Co. and Sierra Pacific Power Co. This is to achieve state policy goals for lower carbon emissions, renewable energy, energy efficiency, and electric vehicle adoption while keeping costs down.

Also, the commission is examining whether alternative rates such as flexible pricing options for customer classes will capture utilities' cost of doing business and support financial stability while assuring the delivery of safe and reliable electricity at a reasonable cost. The final determination is expected in 2021, and we will continue to monitor developments.

New York

Political attention toward utilities in the state was somewhat heightened during the past year following a blackout in summer 2019 in Consolidated Edison Inc.'s (Con Ed) service territory. In addition, Con Ed's and National Grid North America's (NGNA) implementation of gas distribution moratoriums to manage gas supply issues in the region added to the regulatory uncertainty. The moratoriums led to a letter in late 2019 from Gov. Andrew Cuomo indicating the state would move to revoke NGNA's certificate to operate its downstate gas franchise in response to NGNA's management of the gas supply issues in its service territory.

NGNA subsequently agreed to pay $36 million to compensate customers affected by its moratorium and support other energy conservation measures and projects, all of which reduced regulatory uncertainty. However, regulatory risk is still likely to persist because gas supply constraints remain a key issue for gas utilities in the state.

Con Ed has faced political pushback for some of its actions, including on the gas supply moratorium and summer 2019 blackout, but has avoided formal reprimands. This somewhat limits its regulatory and political risks. Despite the negative political attention, Con Ed achieved a

somewhat constructive rate case decision from the New York State Public Service Commission (NYSPSC), including on a multiyear rate plan for its electric and gas operations at Consolidated Edison Co. of New York Inc. for rate increases totaling nearly $1.2 billion over three years beginning in 2020. While the multiyear rate plan provides some cash flow predictability, under this plan the authorized return on equity is 8.8%, lower than what is typical for peers.

New Mexico

In 2019, the state passed the Energy Transition Act (ETA) to eliminate carbon emissions by 2045 from electric utilities with interim targets. We believe this provides credit support to the retirement of fossil-fuel generation in the state. PNM Resources Inc. subsequently sought approval to close units at the San Juan coal-fired plant and securitize the plant abandonment costs. In early 2020, a New Mexico Supreme Court ruling confirmed the applicability of the ETA to PNM's plan and replacement power project. The commission is reviewing different options of the proposed replacement project.

An initiative is expected to be included on the state's 2020 general election ballot that, if approved, would require Public Regulation Commission members to be appointed. The constitutional amendment would change the PRC from a five-person elected body to a three-person agency, with members chosen by the governor from a list of candidates compiled by a nominating committee, beginning in 2023.

North Carolina

While some developments suggest possible improvement to regulatory risks, other issues remain unresolved. Specifically, passage of Senate Bill 559, a storm securitization measure, permits recovery for certain storm recovery costs. Duke Energy Corp. utilities Duke Energy Carolinas LLC and Duke Energy Progress LLC can use a new financing measure to recover restoration costs incurred after several storms and hurricanes in 2018. We consider this favorable for credit quality. Separately, in 2019, Duke Energy settled with the North Carolina Department of Environmental Quality and certain community groups to excavate seven of the nine remaining coal ash basins in North Carolina and partly excavate the other two. Although this reduces legal uncertainty associated with the company's ash pond closure strategy, cost recovery for coal ash costs is still pending, which indicates some regulatory uncertainty.

Texas

We have not revised our regulatory jurisdiction assessment on the Public Utilities Commission of Texas (PUCT), which we consider to be very credit supportive. But we believe recent orders related to COVID-19 in addition to noteworthy trends stemming from recent rate proceedings require a comment.

In March 2020, PUCT issued orders related to COVID-19, suspending utility service disconnections for nonpayment and creating the COVID-19 Electricity Relief Program. We find this program to be constructive from a credit standpoint, specifically as it relates to the recoverability of unexpected costs arising from customer nonpayment due to the pandemic. We believe PUCT's action to be more proactive and demonstrates a commitment to credit quality compared to responses from other jurisdictions that relied only on deferrals of these costs as regulatory assets.

In multiple recent rate case decisions, PUCT approved more-leveraged hypothetical capital structures that reflect an equity ratio of 42.5%. This differs from previous trends when PUCT

approved equity ratios of 45%. We believe these actions could weaken credit quality as utilities manage equity ratios down to this lower level, possibly weakening financial measures without offsetting adjustments.

Virginia

The Virginia Clean Economy Act passed in March 2020, which requires electric utilities to supply 100% of electricity from renewable sources by 2050. Intermediate targets are also set for utilities, including Virginia Electric & Power Co. and Appalachian Power Co., that require 30% of power to be supplied from renewables by 2030 and to close all carbon-emitting power plants by 2045 and 2050, respectively. The Grid Transformation and Security Act passed in 2018 allows utilities to rate-base large renewable projects. However, certain key risks remain, including concerns on the leveled cost of energy provided by new offshore wind projects, even though lawmakers have been historically supportive to the utilities' effort to expand wind capacity. The Clean Economy Act also grants the Virginia State Corporation Commission more oversight over major projects, including the 2.6-gigawatt offshore wind project with construction slated to start in 2024. Some risks may arise due to potential cost overruns or project delays, which could create pressure on the timely cost recovery and ratepayer affordability. We are closely monitoring the 12-megawatt pilot project, which may complete construction this summer.

Renewable Portfolio Standard And Clean Energy Standards

State-level clean and renewable energy standards greatly influence the overall strategic direction and growth investments of North American regulated utilities. Regulatory support through timely cost recovery helps support credit quality and facilitate the energy transition. A number of states are passing or proposing legislation that would require utilities to further scale back carbon emissions from power plants and utilize a greater percentage of renewable energy generation. Today, 31 states have a mandatory renewable portfolio standard (RPS), and seven have a voluntary renewable energy standard target.

The most recent state to adopt a mandatory RPS target is Virginia, which as of 2020 requires investor-owned utilities to achieve 100% renewable generation by either 2045 or 2050, depending on the entity, and a certain amount from solar and wind sources. Other states are revising their targets or passing additional legislation. Washington passed a bill to achieve net-zero carbon emissions by 2050. Maine requires state greenhouse gas emissions to be below 1990 levels by at least 45% by 2030 and at least 80% by 2050. Iowa, New Mexico, and Maryland have either passed or proposed legislation that would curb emissions and require more clean energy sources.

We will continue to monitor these developments for any impact.

Related Research

- Regulatory Responses To COVID-19 Are Key To Utilities' Credit Prospects, May 20, 2020
- U.S. And Canadian Regulatory Jurisdiction Updates And Insights: November 2019, Nov. 4, 2019
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

This report does not constitute a rating action.

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SEC Interrogatory #24

Interrogatory

Reference: C1-1-1, Attachment 1, p.7, 33

Concentric concludes that "OPG faces an inherently increasing risk related to variability in generation output due to the aging of its nuclear stations". Please show where any of the most recent filed Ratings Reports agree with that conclusion, or even refer to this risk at all.

Response

Response prepared by Concentric Energy Advisors.

Please see Ex. A2-3-1, Attachment 4, p.3, where DBRS Morningstar states "Nuclear generation faces higher operating risks than other types of power generation because of its complex technology (approximately 56% of OPG 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."

Please further see Ex. A2-3-1, Attachment 6, p.2, where Moody's Investors Service lists "[a]vailability risk across the fleet" as one of four credit challenges for OPG. In addition, at p.4 of that same report, Moody's states: "Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets."

SEC Interrogatory #25

Interrogatory

Reference: C1-1-1, Attachment 1, p.8

Please confirm that Concentric disagrees with the OEB's conclusion in EB-2016-0152 that if the output from OPG's nuclear fleet is not increasing, the risk of OPG is not necessarily increase just because of increasing nuclear rate base.

Response

Response Prepared by Concentric Energy Advisors

Concentric assumes that SEC is referring to p.102 of the OEB's Decision and Order in EB-2016-0152 where the OEB specifically stated:

> In this case, 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 nuclear will not change in favour of nuclear, so it is not axiomatic that the equity thickness should be increased on this basis.

Concentric views this statement by the OEB as indicating that increasing rate base alone is not sufficient for determining whether a change in equity thickness is required. In its reaching its conclusions in this report, Concentric carefully considered this finding, as well as the OEB's findings in EB-2013-0321, lowering the equity ratio for OPG from 47% to 45%, that:

> [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.[1]

Concentric's view is that changes in rate base are an important indicator of changes in business risk, especially where nuclear assets are concerned, and that the increase in

[1] EB-2013-0321, Decision with Reasons, at 113.

nuclear rate base alone, with its attendant risk, is supportive of a need for an increased equity thickness for OPG. This is based on the consideration that it is ultimately the investment in plant, not the output itself, that drives the need for capital.

Based on its analysis of the appropriate equity ratio for the upcoming rate setting period, Concentric finds there are also additional factors related to the implications of the relative contributions of OPG's nuclear and hydroelectric businesses that should be considered when setting OPG's equity thickness for the 2022-2026 period, including:

1. 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; and

2. the decline in nuclear generation creates additional risk from a cost recovery perspective over the upcoming period.

To this latter point, the risk arises because each unit of nuclear generation output will become more financially valuable to OPG as nuclear generation that recovers the nuclear revenue requirement is reduced. 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. This is discussed further at Ex. C1-1-1 Attachment 1 pp. 55-61.

SEC Interrogatory #26

Interrogatory

Reference: C1-1-1, Attachment 1, p.9, 36, 60

Concentric concludes that the freeze of the hydroelectric payments amount will result in an increase in OPG's financial risk in two ways: a) by increasing the pressure on OPG to manage inflationary increases in cost, and b) by increasing the differential in revenue value per MWh between nuclear and hydroelectric generation. Please quantify the extent to which this is factored into the expert's proposal to increase OPG's equity thickness by 5%. Please estimate the increase to the equity thickness the expert would propose without these factors.

Response

Response prepared by Concentric Energy Advisors

As described in Ex. C1-1-1, Attachment 1, p.6, Concentric concludes that, based on the totality of the risk factors discussed in Ex. C1-1-1, Attachment 1, there has been a shift in OPG's risk profile since the time of EB-2016-0152 that is sufficient to warrant a reassessment of OPG's equity ratio. Concentric also found, based on an analysis of a proxy group of sufficiently comparable companies, that OPG falls towards the upper end of the risk spectrum of companies with equity ratios ranging from 45.7% to 55.9%. Further, Concentric conservatively recommends an equity ratio of no less than 50%, balancing considerations related to OPG's heightened risk profile and proxy group position with the OEB's findings in EB-2016-1052. As discussed at L-C1-01-Staff-043, Concentric's approach, therefore, did not identify explicit equity thickness increments for each risk factor analyzed.

While Concentric did not analyze the appropriate equity thickness in a counterfactual scenario in which hydroelectric payments were not frozen, the report observed fewer incremental risks related to the regulated hydroelectric facilities than for the nuclear facilities, of which the inflationary risk is one element. Therefore, directionally, Concentric would not expect a scenario absent the hydroelectric rate freeze to yield a significantly different recommendation.

Additionally, Concentric notes that while the Hydroelectric rate freeze increase contributes to the increased differential between nuclear and hydroelectric payment amounts between EB-2016-0152 and this proceeding, it could not reasonably be the primary driver of the increase. As noted at p.58 of the report, the differential almost doubles from $39/MWh to $77/MWh.

SEC Interrogatory #27

Interrogatory

Reference: C1-1-1, Attachment 1, p.27

Please provide the name, affiliation, and CV of the analyst who "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 equity thickness and ROE in Ontario could lead to challenges in incenting capital to flow to the province."

Response

Response prepared by Concentric Energy Advisors.

See the response to Ex. L-C1-01-SEC-22. Analysts who participated in Concentric's survey did so with the understanding that their names and firms would be included in Concentric's report, but without attribution for specific statements. Please see the response to Ex. L-C1-01-CME-024 for the survey questions and full answers provided from the analysts interviewed as part of Concentric's report.

SEC Interrogatory #28

Interrogatory

Reference: C1-1-1, Attachment 1, p.28

Please provide an analysis and table, in the same format as EB-2016-0152, Ex. K18.4, p. 28-31, with the most recent three years of data available to Concentric.

Response

Response prepared by Concentric Energy Advisors.

Please see the response to L-C1-01-Staff-042.

SEC Interrogatory #29

Interrogatory

Reference: C1-1-1, Attachment 1, p.29

With respect to the differences between the cost of capital in Canada and the U.S.:

a. Please provide an analysis of the extent, if any, to which the 13.4% increase 2017 to current in the TSX Index vs. the 51.3% increase in the S&P 500 Index over the same period, should be reflected in estimates of the relative cost of equity capital in Canada and the U.S.
b. Please provide an analysis of the extent, if any, that the consistently lower government and utility bond yields in Canada vs. the U.S. over the 2017 to 2020 period should be reflected in estimates of the relative cost of equity capital in Canada and the U.S.

Response

Response prepared by Concentric Energy Advisors.

a. Concentric has not attempted to measure the relative cost of equity capital in Canada and the U.S. in its report, nor analyze the relative movements of the TSX or S&P 500 for their impact on the cost of capital. The cost of capital is investment specific. For regulated utilities, this analysis is typically performed using market data for a proxy group of risk comparable utilities.

b. Please see the response to part a. Differentials in government bond yields in Canada vs. the U.S. are one factor that investors consider. However, in our interviews with equity analysts, their view was that the bond yield differential between Canada and the U.S. has been relatively small in recent years, and they did not consider this spread as materially affecting the cost of equity capital for utilities in Canada vs. those in the U.S. (see the Concentric report, p.23). Further, the current 10-year government bond yields in the U.S. are only 19 basis points higher than Canada's (1.72% vs. 1.53%), and the most recent long-term interest rate forecast from Consensus Economics (October 2020) indicates that 10-year Canadian government bond yields are forecast to be 10-30 basis points higher than those in the U.S. over the period from 2022-2030.

SEC Interrogatory #30

Interrogatory

Reference: C1-1-1, Attachment 1, p.33

Please confirm that the most recent filed Ratings Reports generally conclude that OPG has no significant climate change risk in its regulated operations, but does have some climate change risk in its unregulated operations [e.g. A2-3-1, Attachment 6, p.7]. Please reconcile the Concentric view that OPG faces increased climate change risk with the most recent filed Ratings Reports.

Response

Response prepared by Concentric Energy Advisors

Not confirmed. For example, Ex. A2-3-1, Attachment 6, p.7 (i.e., Moody's Investors Service December 21, 2020 report), does not conclude that "OPG has no significant climate change risk in its regulated operations." Rather, in a section titled "ESG [Environmental, Social, and Governance] considerations," Moody's notes that OPG's "hydro facilities face some hydrology risk while a long-term nuclear refurbishment entails high execution risk." Moody's further discusses carbon transition risk, and notes that OPG has low risk in that regard, but that is because OPG's hydroelectric and nuclear facilities are non-carbon emitting, rather than due to OPG not facing the physical types of climate change risks discussed in Concentric's report, which primarily relates to operational risks due to extreme weather events.

SEC Interrogatory #31

Interrogatory

Reference: C1-1-1, Attachment 1, p.34, 62

Concentric concludes that "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". Please reconcile this conclusion with:

a. The forecast of S&P Global [A2-3-1. Attachment 11, p.2] that FFO to debt will be at 14-15%, and its conclusion that the FFO pressure is based on debt-funded acquisitions of unregulated assets.
b. The forecast of Moody's [A2-3-1. Attachment 6, p.1-2,6] that CFO to debt will be 12-16%, and its similar conclusion that the prime cause of any decline is debt-funded acquisitions of unregulated assets.
c. Moody's note [A2-3-1, Attachment 6, p.3] that a downgrade would only be likely if CFO/debt drops below 12% "on a sustained basis".
d. The statement of DBRS [A2-3-1, Attachment 4, p. 1-2, 13] that "the cash flow to debt and debt to capital metrics are forecast to remain strong...", and its conclusion that "should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations or lead to credit metrics deteriorating to a level no longer supportive over the current rating category, DBRS Morningstar may take negative rating action."

Response

Response prepared by Concentric Energy Advisors

a) As described in Ex. C1-1-1, Attachment 1 the statement cited in the interrogatory is based on OPG's business plan. The difference in results from S&P's forecast could derive from timing differences. Concentric disagrees with the statement in the interrogatory that S&P's "conclusion that the FFO pressure is based on debt-funded acquisitions of unregulated assets." S&P identifies further unregulated acquisitions as one of several risk factors. For example, in describing its base-case scenario for OPG in Ex. A2-3-1, Attachment 11, p. 2, S&P states:

> Under our base-case forecast that includes fewer planned outage days for nuclear plants in 2020, average annual capital expenditure of about C$2 billion, approved rate case for 2017-2021, and no significant acquisitions for the next

> one to two years, we forecast FFO to debt around 14%-15% for 2020-2022.

Similarly, with respect to the downside scenario at p. 3 of same evidence, S&P notes that a weakening of FFO to debt could trigger a negative rating action in the next 12-18 months "if the company experiences delays and cost overruns at its Darlington refurbishment program, adverse regulatory decisions, or significant debt-funded acquisitions."

b) Concentric agrees that Moody's identifies the risk to credit metrics from recently completed debt-funded acquisitions; however, Moody's also recognizes the pressures on OPG's credit profile from the regulated business, consistent with Concentric's assessment. For example, at Ex. A2-3-1, Attachment 6, p.6, Moody's states "Financial metrics will decline as the company digests recent debt financed acquisitions and the nuclear business, which has benefited from higher than anticipated generation levels, sees a reduction in generation levels." Additionally, as discussed in VECC-10, Moody's considers the use of rate smoothing to be credit negative, noting that "To offset the deferred revenue, the balance of the RSDA will be 100% debt financed at a long-term debt rate, putting more pressure on financial metrics" (Moody's Investors Service, "Ontario Power Generation Inc., "Proposed increase in rate smoothing is credit negative," January 26, 2021). Additionally, in discussing OPG's "credit challenges," Moody's (Ex. A2-3-1. Attachment 6, p. 2) also identifies OPG's nuclear refurbishment and "[a]vailability risks across the fleet." Differences in credit metric results from Moody's forecast could derive from timing differences.

c) Moody's (Ex. A2-3-1, Attachment 6, p. 3) cites four factors that could lead to a downgrade for OPG, including:

1. "[c]hallenges or delays executing the Darlington nuclear refurbishment;"
2. "[a] weakening of the business risk profile by, for example, further growing the merchant segment;"
3. "[a] reduction in the probability of support from the Province;" and
4. "[a] deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 12% on a sustained basis."

There is no inconsistency between Moody's assessment of a sustained decline in credit metrics before issuing a credit downgrade and the findings in Concentric's report. For example, at Ex. C1-1-1, Attachment 1, p. 59, Concentric stated "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." Moody's does not define

"sustained basis." Concentric is not privy to the specific basis for Moody's forecast of financial metrics for OPG.

d) While DBRS Morningstar identifies that significant future expansion of OPG's unregulated business would be a source of negative rating action risk, it has specifically noted that the overall impact of the recent $2.8 billion gas plant acquisition "on OPG's credit will be minimal because regulated operations and assets under regulatory-style contracts will continue to contribute over 80% of EBITDA." ("Ex. A2-3-1, Attachment 4, p. 2) Further, similar to Moody's, DBRS states that "a downgrade could occur should there be significant cost overruns with the Darlington Refurbishment that result in stranded costs" (Ex. A2-3-1, Att. 4, p. 2). Other "challenges" identified include nuclear generation risks, OEB cost disallowances and political intervention. This assessment is not inconsistent with Concentric's review of OPG's regulated business.

SEC Interrogatory #32

Interrogatory

Reference: C1-1-1, Attachment 1, p.34-5, 58

Please provide a rate base, capital additions, and depreciation continuity table for the regulated hydroelectric stations over the period 2022-2026 showing the forecast of $2.0 of capital spending, demonstrating how it is "being made primarily to replace aging infrastructure and upgrade/develop certain sites", and showing that by 2026 regulated hydroelectric will have a rate base of $8.9 billion, 40% of the total rate base of OPG.

Response

The requested tables are provided in Attachment 1.

Investment to replace aging infrastructure and upgrade/redevelop certain regulated hydroelectric sites is discussed within OPG's 2020-2026 Business Plan filed as Ex. A2-2-1, Attachment 1, pp. 31, 33-34.

Numbers may not add due to rounding.

Table 1
Prescribed Facility Rate Base - Regulated Hydroelectric ($B)
Years Ending December 31, 2022 to 2026

Line No.	2022 Budget			2023 Budget			2024 Budget		
	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	10.6	2.8	7.8	11.0	3.0	8.0	11.3	3.1	8.2

Line No.	2025 Budget			2026 Budget		
	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
	(a)	(b)	(c)	(d)	(e)	(f)
2	11.8	3.3	8.5	12.3	3.5	8.9

Table 2
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric ($B)
Years Ending December 31, 2022 to 2026

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount[1]
		(a)	(b)	(c)	(d)	(e)	(f)
1	**2022 Budget**	10.4	0.5	(0.0)	0.5	10.9	10.6
2	**2023 Budget**	10.9	0.2	(0.0)	0.2	11.1	11.0
3	**2024 Budget**	11.1	0.4	(0.0)	0.4	11.5	11.3
4	**2025 Budget**	11.5	0.6	(0.0)	0.6	12.1	11.8
5	**2026 Budget**	12.1	0.5	(0.0)	0.5	12.5	12.3

Notes

1 Consistent with OPG's rate base methodology discussed at Ex. B1-1-1, section 3.1.2, a monthly weighting was applied to any known projected in-service additions over $50M.

Numbers may not add due to rounding.

Table 3
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric ($B)
Years Ending December 31, 2022 to 2026

Line No.	Year	Opening Balance	Depreciation and Amortization on Opening Balance	Depreciation and Amortization on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
1	**2022 Budget**	2.7	0.1	0.0	0.0	2.9	2.8
2	**2023 Budget**	2.9	0.2	0.0	0.0	3.1	3.0
3	**2024 Budget**	3.1	0.2	0.0	0.0	3.2	3.1
4	**2025 Budget**	3.2	0.2	0.0	0.0	3.4	3.3
5	**2026 Budget**	3.4	0.2	0.0	0.0	3.5	3.5

SEC Interrogatory #33

Interrogatory

Reference: C1-1-1, Attachment 1, p.46

Concentric concludes that the aging nuclear units "face an inherent risk of experiencing increased effects of aging on their operations and output". With respect to this conclusion:

a. Please reconcile this conclusion with OPG's forecasts of nuclear repair and maintenance costs and forced loss rates in 2022-2026.
b. Please identify where, in A2-3-1, Attachments 4, 6 or 11, the most recent reports of the rating agencies flag a similar risk.

Response

Response prepared by Concentric Energy Advisors.

a. OPG's setting of operating targets and Concentric's assessment of risk from an investor's perspective are not in conflict, as they are conceptually different (one being setting targets and the other being risks to achieving those targets). Moreover, OPG's evidence and business plan acknowledge the risks and challenges to achieving its targets. For example, Ex. E2-1-1 states at p. 1 that "both Pickering and Darlington pre-refurbishment are aging facilities that inherently face equipment issues and increased maintenance requirements," and at p. 14, with respect to the Darlington forced loss rate target pre-refurbishment that "the recent historical performance represents a potential challenge to the 1% FLR target." While OPG's evidence does not provide a direct link between maintenance costs and equipment age, OPG's business plan identifies the "risk of increased operating costs from greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, scope changes and equipment failures" (Ex. A2-2-1, Attachment 1, p. 43). Additionally, the ScottMadden OPG Nuclear Cost Performance Benchmarking report concludes that each month of average unit age increases the predicted TGC by C$346,000 per year (Ex. F2-1-1 Attachment 5, p. 4).

b. See response to Ex. L-C1-01-SEC-024.

SEC Interrogatory #34

Interrogatory

Reference: C1-1-1, Attachment 1, p.51

With respect to the National Capital Commission report cited in footnote 71, please confirm:

a. The report forecasts using the IPCC intermediate (RCP4.5) and worst-case (RCP8.5) scenarios.
b. The report forecasts (p. 33) annual precipitation over the 2020 to 2050 period to increase by 3% under the intermediate scenario (921 mm to 949 mm) and 5% under the worst-case scenario (921 mm to 968 mm).
c. The report forecasts no significant increase in annual precipitation prior to 2030 in either scenario.
d. The report specifically declines (p. 71-2) to issue any forecast of additional flooding on the Ottawa River over any period out to the end of the century.

Response

Response prepared by Concentric Energy Advisors.

a. Confirmed. As described on page ii of the National Capital Commission ("NCC") report, "[a]s the low emission scenario is considered unlikely, this study provides a range of results for the moderate to high emission scenarios (RCP 4.5 and RCP 8.5) for 3 projection horizons, or time slices, when compared to the 1981-2010 baseline: 2030s (2021-2050), 2050s (2041-2070), 2080s (2071-2100)."

b. Confirmed.

c. Not confirmed. The NCC report clarifies on page 18 that the values summarized in its key findings "represent an 'average year' (since they are averaged over 30-year time slices)". As described in the response to part (a), above, the NCC defines the 2030s as 2021-2050. As confirmed in the response to part (b) above, the NCC report forecasts annual precipitation to increase by 3% under the intermediate scenario and 5% under the worst-case scenario in the 2030s.

d. Confirmed in part. While the NCC report indicates that complex watershed-scale projections would be required to properly project flood risks, it also notes on page 71 that some of the projected environmental changes (i.e., in snowfall, rainfall, and temperature) are environmental drivers of flooding. The NCC report also notes that

the Gatineau, Rideau and Ottawa rivers have experienced significant flooding, most recently in 2017 and 2019.

SEC Interrogatory #35

Interrogatory

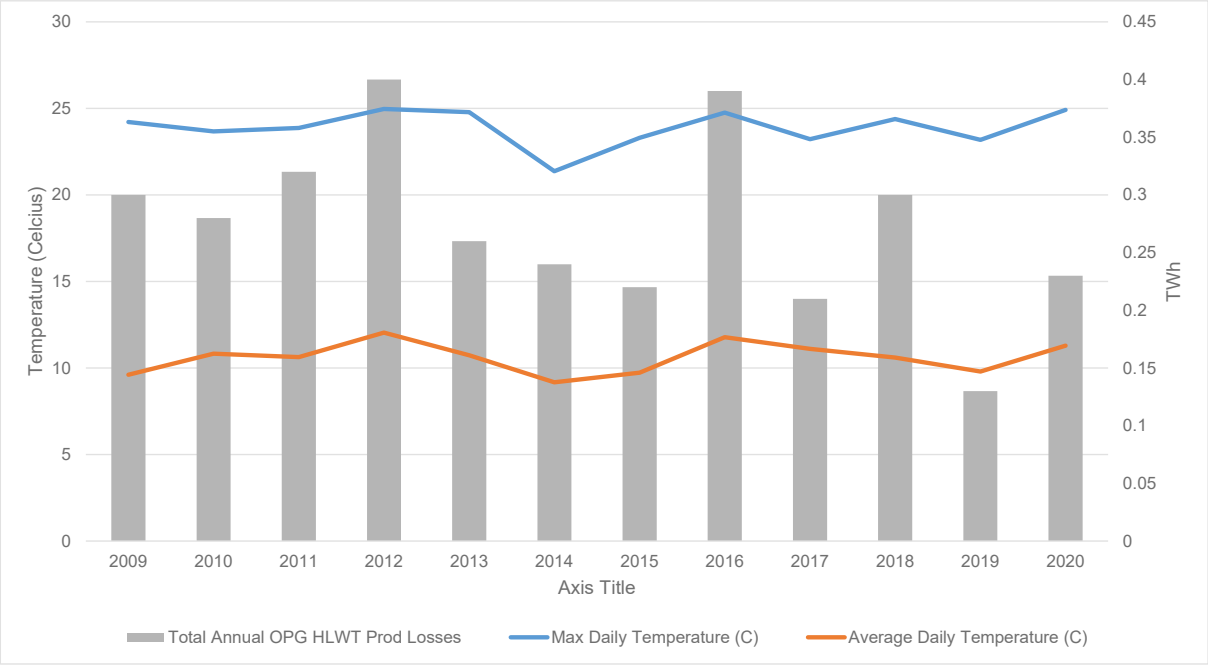
Reference: C1-1-1, Attachment 1, p.51

Please provide a table from 2000 to 2020 showing the relationship between increasing lake water temperatures in Lake Ontario and "lower output through unit derates" for nuclear stations.

Response

OPG does not have this information dating back to 2000. Chart 1 below provides the lake Ontario surface water temperatures against the production losses due to high lake water temperatures.

Chart 1:
Lake Ontario Surface Water Temperatures and High Lake Water Temperature Production Losses



Witness Panel: Finance and D&V Accounts

SEC Interrogatory #36

Interrogatory

Reference: C1-1-1, Attachment 1, p.52

Please comment on whether the increasing push to a lower carbon future could result in reduced opposition to nuclear power amongst the public because it is a carbon zero fuel.

Response

Response prepared by Concentric Energy Advisors

Carbon emissions are just one of many factors that inform the public's view of the desirability of nuclear based power. Waste disposal, safety concerns and cost effectiveness are also key factors. All else being equal, nuclear power's status as a source of zero carbon emissions could result in reduced opposition among the public, but we have yet to see this evidenced. Also, please see the response to Ex. L-C1-01-Staff-55 for a discussion of how credit rating agencies and investors view the risk of nuclear generation.

SEC Interrogatory #37

Interrogatory

Reference: C1-1-1, Attachment 1, p.54

Please provide specifics of why Concentric believes that the impacts of climate change on OPG's regulated operations will make it a more risky investment relative to other investments that would be of interest to the same investors.

Response

Response prepared by Concentric Energy Advisors

Concentric's report does not conclude that "impacts of climate change on OPG's regulated operations will make it a more risky investment relative to other investments that would be of interest to the same investors." Concentric's report discusses climate change risk on pp. 47-51. The focus of this discussion is on how the increased risk of climate change affects the generating industry generally, the operating performance of OPG's generating assets in particular, and the overall economy and financial markets, concluding that the risk has increased for OPG since EB-2016-0152.

SEC Interrogatory #38

Interrogatory

Reference: C1-1-1, Attachment 1, p.59

Please restate Figure 11 so that, similar to Figure 10, it shows the percentage of TWh. for nuclear for each year, and for each of the prior and upcoming rate periods. Please confirm that the percentage of nuclear output in the 2017-2021 period is forecast at 56.7%, and is expected to decline in the 2022-2026 period to 47.5%. Please confirm that the percentage of nuclear output in 2017 was 57.0%, and that is expected to decline to 39.4% in 2026.

Response

Response Prepared by Concentric Energy Advisors

Confirmed, subject to minor rounding differences. Please see Chart 1 below.

Chart 1: 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**
Hydro [1]	30.7	29.9	30.5	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Nuclear	40.7	40.9	43.5	42.7	38.3	33.2	30.8	33.3	30.2	21.5
Nuclear Portion of Generation	57.0%	57.8%	58.8%	56.4%	53.7%	50.2%	48.3%	50.2%	47.8%	39.4%
Rate Term Ratio Avg	56.7%					47.2%				

[1] 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.

SEC Interrogatory #39

Interrogatory

Reference: C1-1-1, Attachment 1, p.63

Please explain why no government-owned utilities were included in the proxy group.

Response

Response prepared by Concentric Energy Advisors

As described in Ex. C1-1-1, Attachment 1, p. 61, the cost of capital is a market-based concept. Accordingly, Concentric selected publicly traded proxy companies in part to ensure that utilities included in the proxy group had market-based capital structures. Further, many government-owned utilities have credit ratings that are materially higher than OPG's (e.g., Tennessee Valley Authority is rated Aaa by Moody's Investors Service ("Moody's"), British Columbia Hydro and Power Authority is rated Aaa by Moody's, and Hydro-Quebec is rated Aa2 by Moody's). Therefore, Concentric excluded government-owned utilities from its proxy group because those utilities do not provide meaningful data regarding the capital structure for OPG.

SEC Interrogatory #40

Interrogatory

Reference: C1-1-1, Attachment 1, p.70

Please explain what the term "Strong" means which it is used by S&P to describe business risk.

Response

Response Prepared by Concentric Energy Advisors

"Strong" is the second of six business risk profiles S&P assesses for companies it covers. The business risk profiles, in order from most credit supportive to least credit supportive, are:

1. Excellent;
2. Strong;
3. Satisfactory;
4. Fair;
5. Weak; and
6. Vulnerable

S&P combines its assessments of an issuer's business risk profile and financial risk profile to assess an "anchor" score for an issuer, which might then be further modified based on additional factors to assess the stand-alone credit profile. Based on S&P's assessment of OPG's business and financial risks, S&P assigns OPG an anchor rating of bbb, which it then modifies down two notches to a bb+ stand-alone credit rating, which is the rating of OPG as a standalone company without consideration of Provincial support.

S&P describes an issuer in the "BB" category as follows: "An obligor rated 'BB' is less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments."[1]

[1] S&P Global Ratings, "S&P Global Ratings Definitions," June 26, 2017

SEC Interrogatory #41

Interrogatory

Reference: C1-1-1, Attachment 1, p.75

Please provide a quantitative comparison to show that OPG has historically recovered a lower percentage of its deferral and variance accounts than other electric utilities in Ontario.

Response

Response prepared by Concentric Energy Advisors

Concentric's report does not assert that "OPG has historically recovered a lower percentage of its deferral and variance accounts than other electric utilities in Ontario," nor has Concentric conducted the quantitative comparison requested. As discussed in Concentric's Report at pages 71-72, and in the response to L-C1-01Staff-047, Concentric considered the general comparability of OPG's deferral and variance accounts ("DVAs") to other regulated electric utilities in Ontario, and considered related risks on a forward-looking basis. Concentric observed that the majority of OPG's DVAs would be classified as Group 2 accounts, which require a prudence review by the OEB before the utility is allowed to recover these costs. By contrast, Group 1 accounts do not require a prudence review. Concentric also reviewed a sample of other electric utilities in Ontario and determined that those companies have a mix of Group 1 and Group 2 DVAs. On that basis, Concentric concluded that OPG has relatively greater risk related to cost recovery for its DVAs than do other electric utilities in Ontario.

In any event, it is not feasible to perform the analysis requested within the period provided for interrogatory responses as it would require a detailed review and analysis of filed evidence and decisions in dozens of OEB rate applications.

SEC Interrogatory #42

Interrogatory

Reference: C1-1-1, Attachment 1

Please reconcile Concentric's conclusion that "OPG's risk profile will increase materially" with:

a. The statement by S&P Global [A2-3-1. Attachment 11, p.1] "We are also revising upwards our business risk profile on OPG to strong from satisfactory".
b. The statement by Moody's [A2-3-1, Attachment 6, p.4] "OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow".

Response

Response prepared by Concentric Energy Advisors

For clarification, the complete statement excerpted in the interrogatory was: "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." This conclusion was based on Concentric's assessment of whether OPG's business risk profile has changed since EB-2016-0152.

a) At the time of EB-2016-0152, S&P assessed OPG's business risk profile as "strong." In the intervening years, S&P re-assessed OPG's business risk profile downwards to "satisfactory" on June 25, 2019, and then back to "strong" on July 17, 2020. Further, as of EB-2016-0152, S&P modified OPG's anchor score (discussed in the response to SEC-40) upwards by one notch under its "comparable rating analysis" to a stand-alone credit profile of bbb-, whereas S&P currently modifies OPG's anchor score downwards by one notch under its comparable rating analysis to a stand-alone credit profile of bb+. This represents S&P's assessment of a weaker risk profile given OPG's operational and financial risk profile based on its methodology.

b) Moody's Investors Service's ("Moody's") did not cover OPG as of EB-2016-0152, so there is no point of comparison for Moody's assessment against Concentric's. Further, Moody's assessment of OPG's strong business risk profile is not in conflict with Concentric's assessment of the change in OPG's risk profile between EB-2016-0152 and the current case. Because of their strong business risk profiles,

underpinned by rate-regulated utility revenues, North American utilities, including OPG, are typically afforded higher credit ratings than they would be if they operated in competitive markets. This is demonstrated in Figure 16 of Concentric's report, which shows that OPG and all the utilities in the Concentric proxy group have business risk assessments of either "strong" (eight companies, including OPG) or "excellent" (12 companies) from S&P.

SEC Interrogatory #43

Interrogatory

Reference: C1-1-1, Attachment 1

Please reconcile Concentric's conclusion that OPG's equity thickness should be increased from 45% to 50% with the DBRS rating [A2-3-1, Attachment 4, p.10] of the Deemed Equity of OPG, at 45%, as Good, the second highest of five levels of rating.

Response

Response prepared by Concentric Energy Advisors

There is no inconsistency between Concentric's recommendation regarding OPG's equity thickness and DBRS assessing a "Good" score to OPG's current deemed equity thickness of 45%. Concentric's recommendation is not aimed at OPG achieving a particular score in DBRS' framework. Rather, Concentric's recommendation is focused on recommending an equity ratio for OPG that is consistent with those of peer utilities and one that satisfies the fair return standard.

Further, and for additional context, "Deemed Equity" is one of eight criteria considered by DBRS in its assessment of regulatory framework, with scores for OPG including "Below Average" (political interference), "Satisfactory" (allowed ROE, COS versus IRM, and stranded cost recovery) and "Good" (deemed equity, capital and operating cost recovery, and rate freeze). Based on this assessment, DBRS concludes that "OPG benefits from a reasonable regulated environment." "Reasonable" is the third of four scores DBRS provides in its assessment of regulation, falling after "highly supportive," and "supportive," but before "poor" (see, DBRS, "Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," September 2019, p. 6). Additionally, Concentric notes that 45% is the minimum equity ratio for DBRS to consider a deemed equity ratio to be "Good," with the "Good" score applying to deemed equity ratios of 45% to 49.99% (DBRS, "Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," September 2019, p. 12).

SEC Interrogatory #44

Interrogatory

Reference: C1-1-1, Attachment 1

Please confirm that Concentric is recommending an increase from 45% equity to 50% equity for all of the prescribed facilities, nuclear and hydroelectric. Please confirm that, because of the freeze of the hydroelectric payment amounts, the Applicant is proposing that this increase only be applied to the nuclear rate base, and that the increase that would otherwise be applicable to the hydroelectric rate base will not be collected by OPG, directly or indirectly, for the period 2022-2026.

Response

Confirmed and confirmed.

SEC Interrogatory #45

Interrogatory

Reference: C1-1-1, Tables 1-11

Please confirm that the increase in the after-tax cost of nuclear equity for 2022-2026 is $844.1 million ($1,148.4 million grossed-up), of which $400.0 million (544.1 million grossed-up) is the result of the proposed increase in equity thickness from 45% to 50%.

Response

Not confirmed.

OPG calculates the revenue deficiency component related to the nuclear return on equity (grossed-up for income tax) to be $1,051.2M over the 2022-2026 period, as shown below. This includes the impact of changes in rate base, ROE rate and proposed capital structure. Consistent with Ex. A1-3-3, the revenue deficiency is calculated relative to the OEB-approved revenue requirement for the 2021 year.

Chart 1: Nuclear Return on Equity Revenue Deficiency

$M	2022	2023	2024	2025	2026	Total
EB-2020-0290 Proposed [1]	480.8	488.7	626.1	693.2	740.1	3,028.9
EB-2016-0152 OEB Approved (2021) [2]	395.5	395.5	395.5	395.5	395.5	1,977.7
Return on Equity Deficiency	85.3	93.2	230.6	297.7	344.6	1,051.2

1) EB-2020-0290 Ex. I1-1-1 Table 1, cols. (a) to (e), line 12 + same reference x 25%/(1-25%)
2) EB-2016-0152 Payment Amounts Order, App. A, Table 5, col. (c), line 12 + same reference x 25%/(1-25%)

The impact of the proposed change in capital structure included in the above can be found in response to Ex. L-C1-01-CCC-027 and totals $203.8M over the 2022-2026 period.

SEC Interrogatory #46

Interrogatory

Reference: C1-1-2, Table 12

Please confirm that the actual cost of interest on long term debt applicable to the regulated hydroelectric facilities for the period 2022-2026 is forecast to be approximately $130 million lower than the interest cost embedded in rates for that period.

Response

OPG declines to respond on the basis of relevance. O. Reg. 53/05 section 6(2), 13, i, establishes the Hydroelectric payment amounts for the period covered by this application at the level that exists on December 31, 2021. As such, the information sought is not relevant to any issue before the OEB in this application.

Board Staff Interrogatory #36

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 2 / p. 5 / Chart 3
Exhibit C1 / Tab 1 / Schedule 2 / Table 10A and Table 12A

Preamble:

Chart 3 at Exhibit C1 / Tab 1 / Schedule 2 shows no forecasted debt issuances for 2024 to 2026. In Table 10A at C1 / Tab 1 / Schedule 2, OPG lists the debt of $400 million labelled as Issue 39 as having an Issue Date of 3/16/2024. Similarly, in Table 12A, OPG lists debt labelled Issue 29 as having an Issue Date of 11/22/2026.

Question(s):

a) In Table 10A, please confirm that 3/16/2024 is the Maturity Date, rather than the Issuance Date, of Issue 39 (i.e. that this debt, which seems to have been issued in 2020, is maturing on 3/16/2024).

b) In Table 12A, please confirm that 11/22/2026 is the Maturity Date, rather than the Issuance Date, of Issue 29 (i.e. that this debt, which seems to have been issued in 2016, is maturing on 11/22/2026).

Response

a) Confirmed.

b) Confirmed.

Board Staff Interrogatory #37

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 3 / p. 1

Preamble:

OPG stated that it terminated its accounts receivable securitization program in November 2020.

Question(s):

a) Please provide further explanation regarding why OPG terminated its accounts securitization program, and how this has impacted OPG's short-term debt financing relative to its past practice.

Response

a) OPG terminated the accounts receivable securitization program as more cost effective alternatives were available such as the Canadian and US commercial paper programs. There has been no impact on OPG's short-term debt financing relative to its past practice.

Board Staff Interrogatory #38

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 3 / Table 2
EB-2016-0152 / Decision and Order, December 28, 2017 / p. 111 / Table 32

Preamble:

OEB staff has prepared the following table comparing the forecasts of OPG's short-term debt rate, as agreed upon in the partial settlement proposal in the 2017-2021 Payment Amounts Proceeding, relative to the actual (or expected actual) short-term interest rate for 2017 to 2021 as shown in Table 2 of Exhibit C1 / Tab 1 / Schedule 3. Also shown are the forecasts for the 2022 to 2026 period.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Forecasted (EB-2016-0152)[1]	1.41%	2.73%	3.75%	3.80%	3.65%					
Actual[2]	0.79%	1.10%	1.67%	1.96%	0.70%					
Forecasted (EB-2020-0290)[7]						0.44%	0.47%	0.78%	1.16%	1.66%

Question(s):

a) Please confirm or correct the data shown in the table.

b) Has OPG reviewed its methodology for forecasting short-term interest rates as a result of comparing the forecasts to actuals for historical periods?

c) If yes to part (b), please indicate OPG's findings as a result of such a review. In particular, please describe any changes made to OPG's methodology as a result of any such review.

d) If OPG has not conducted any such reviews, please explain why not.

[1] EB-2016-0152 / Decision and Order / December 28, 2017 / p. 111 / Table 32.
[2] Exhibit C1 / Tab 1 / Schedule 3 / Table 2.

Response

a) Corrected table is shown below.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Forecasted (EB-2016-0152)	1.41%	2.73%	3.75%	3.80%	3.65%					
Actual	1.10%	1.67%	1.96%	0.70%						
Forecasted (EB-2020-0290)					0.44%	0.47%	0.78%	1.16%	1.66%	2.23%

b) No. OPG does not attribute the difference between forecasted and actual interest rates to any deficiencies with the forecasting methodology. The difference reflects the general trend of lower interest rate levels experienced during the last number of years as an expression of macroeconomic factors. In 2020, this included the extraordinary impacts of an economic slowdown and government response as a result of the COVID-19 pandemic.

Although interest rates are subject to a wide range of forces impacting the economy and are difficult to forecast, OPG believes that its forecasting approach continues to provide a transparent and supportable basis for establishing the cost of debt for revenue requirement purposes. In particular, OPG has consistently used a reputable economic forecaster (IHS Global Insight) to provide the main input into its forecast of short-term interest rates. OPG notes that one common feature of interest rate forecasts is the expectation that rates will eventually rise in future periods reflecting the positive impacts of a growing economy on the financial markets.

c) See part b).

d) See part b).

Board Staff Interrogatory #39

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 3 / p. 1
Exhibit C1 / Tab 1 / Schedule 3 / Table 2

Preamble:

OPG noted that its short-term debt is comprised of a commercial paper program backstopped by bank credit facilities. In November 2019, OPG established a second bank facility of USD $750 million. The US bank credit facility diversifies OPG's source of short-term funding beyond the existing $1 billion Canadian bank credit facility.

The cost of OPG's credit facilities is $5.2 million for each year of the Custom IR term as shown at Line 4 of Exhibit C1 / Tab 1 / Schedule 3 / Table 2. This compares to approximately $2.5 million for each year during the period 2016-2019 (prior to the establishment of the US credit facility).

Question(s):

a) Please explain why OPG determined that it was necessary to establish a second bank facility.

b) Please provide the breakdown of the bank facility costs between the US and Canadian credit facilities.

Response

a) The second bank facility provides an additional liquidity source to OPG and diversifies OPG's funding sources, primarily from lenders outside of the Canadian market. The facility provides an alternative source of short-term financing, particularly during periods of market disruption, at more competitive rates than the previous accounts receivable securitization program. The additional liquidity also supports OPG's US dollar commercial paper program, which further diversifies access to short term funding and allows OPG to take advantage of the fact that US and Canadian commercial paper markets can be affected by different factors and have different investors.

b) The breakdown of annual bank facility costs of $5.2M attributed to the nuclear facilities is $2.5M for the Canadian credit facility and $2.7M for the US credit facility.

Board Staff Interrogatory #40

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1

Question(s):

Please provide copies of the following documents referenced in the Concentric Report.

a) Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, referenced at page 20, footnote 30.

b) Moody's Investors Service, Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation, September 23, 2013, referenced at page 21, footnote 31.

c) Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, referenced at page 35, footnote 40.

d) S&P Global Ratings, Research Update: SNC-Lavalin Group Inc. 'BB+' Ratings Affirmed; Outlook Remains Negative On Slower-Than-Expected Deleveraging, May 2020, referenced at page 39, footnote 48.

e) OPG, Quarterly Risk Report – Q2 FY2020, August 11, 2020, referenced at page 48, footnote 69.

f) McKinsey and Company, Why, and how, utilities should start to manage climate change risk, April 2019, referenced at page 50, footnote 82.

Response

Response prepared by Concentric Energy Advisors.

a) See Attachment 1.

b) See Attachment 2.

c) See Attachment 3.

d) See Attachment 4.

e) See Attachment 5.

f) See Attachment 6.

Scotiabank

EQUITY RESEARCH | SPOTLIGHT

Monday, March 18, 2019, Pre-market

Energy Infrastructure

To 2021 and Beyond! Introducing Utility 2021 Estimates and Updating Target Prices

OUR TAKE: We introduce our 2021 estimates for the Canadian utilities and provide perspective on our outlook for the group and its valuation relative to U.S. peers. In 2019 to 2021, we forecast a 6.5% EPS CAGR for the group, slightly ahead of the growth from the U.S. utilities under coverage by our Scotia Howard Weil colleague Andrew Weisel. To reflect a lower bond yield outlook, we also increase our target P/E multiples to an average of 16.4x from 15.9x, more in line with the U.S. peers. The net result is a 9% average increase in our target prices. Our valuation assumes that bond yields rise through 2019, though if yields stay at recent levels this implies another 6% upside. The utilities have performed well in 2019, though less than our pipeline/midstream/power coverage. Given our expectation of rising rates, we maintain our ratings with Algonquin as our favourite name. But investors looking to take a more defensive stance (and with a lower yield outlook) could find Emera and Fortis attractive. In the near term, the sale of Emera's Maine utility could be well received by the market.

KEY POINTS

2021 Estimates + Lower Yields = Higher Targets. The potential for slowing global growth means that monetary policy should be more accommodating than we previously thought. Scotia Economics sees the weakness as temporary with yields rising off the recent lows (link), though less than previously expected. We increase our target P/E multiples by 0.5x for the group, though they are below recent forward multiples.

Algonquin – Greening the Fleet Likely a Go. In 2021 we expect Algonquin to generate above-average EPS growth of 9% y/y. In part driving this are the incremental returns from new renewable projects as well as standard rate base growth. Our estimates assume that Algonquin's US$1.4b Greening the Fleet initiatives proceed, which would see wind farms purchased in Missouri with new rates effective mid-2021. Our US$13.00 target price (up from US$12.00) is based on a 16.75x P/E.

Emera – Maine Sale Should Improve Funding Outlook. Emera's 5% EPS growth in 2021 is a result of 6% rate base growth, partially offset by continued de-levering. We expect Emera to announce the sale of its Maine utility soon, which could be well received by the market. We estimate a $1.3b value, which should remove the need for a common equity issuance. Our $51 target price (up from $46) is based on a 16.75x target P/E. While still a discount to Fortis, we believe that the discount should narrow to reflect the improved funding outlook and strong Florida growth profile.

Fortis – Set It and Forget It. Fortis's 2021E EPS growth of 6% is right in line with its expected rate base growth for that year. Fortis's growth rate, easily achievable funding plan, and high-quality asset base warrant a premium multiple, in our opinion. Our $51 target price (up from $45) is predicated on a 17.0x target P/E.

Hydro One – Higher Returns Under IR, but Risks Remain. We see Hydro One's EPS growing 6% y/y in 2021E as the utility should benefit from rate base growth (5%) and slightly higher achieved ROEs under incentive regulation (IR). Given continuing political and regulatory uncertainty in Ontario, we believe Hydro One warrants a discounted multiple. Our $22 target price (up from $21) is based on a 15.0x multiple.

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COVERAGE SUMMARY

	Rating	1-Yr. Target	Return
AQN-N*	SO	US$13.00	20.7%
EMA-T*	SP	C$51.00	8.9%
FTS-T*	SP	C$51.00	7.7%
H-T*	SP	C$22.00	12.4%

*Companies with pertinent revisions

Growth Continues in 2021 – Key Drivers for Each Company

Algonquin (Sector Outperform; US$13.00 TP)

Top-tier growth – 2021 EPS growth of 9%. The development of renewable projects – both contracted (unregulated) and inside rate base – is a key area of growth for Algonquin. In 2019-2023, Management sees a US$7.5b capital plan, which includes regulated investment (69%), renewable projects (23%), and international opportunities (8%). Since we generally do not include unsecured projects in our model, we handicap this growth outlook in the outer years quite heavily. That said, the company historically has been able to sanction projects, which would be additive to our longer-term forecasts. We forecast 9% EPS growth in 2021, which would be at the bottom end of management's 2017-2023 EPS CAGR range of 9-13%. That said, Algonquin could potentially secure some additional wind projects that would be in service for 2021.

Exhibit 1: Alqonquin – Estimate Overview (US$)

Key Metrics		2018A	2019E	2020E	2021E
Adj. EBITDA	$M	747	830	912	1,019
YoY Growth	%	10%	11%	10%	12%
Adj. EBITDA (Ex. HLBV; Inc. PAYGO)	$M	675	775	854	950
YoY Growth	%	3%	15%	10%	11%
Adj. EPS (diluted)	$/shr	0.59	0.66	0.73	0.79
YoY Growth	%	4%	13%	10%	9%
FCF/shr	$/shr	0.75	0.67	0.74	0.77
YoY Growth	%	53%	(12%)	11%	5%
DPS	C$/shr	0.50	0.55	0.61	0.67
YoY Growth	%	10%	10%	10%	10%

Source: Company reports; Scotiabank GBM estimates.

"Greening the Fleet" – we think it's a go. We have for some time written about Algonquin's "Greening the Fleet" initiative, which involves the expected 2021 purchase of US$1.4b of wind farms in Missouri. The projects continue to hit key milestones and at this point we include them in our 2021 estimates. The Missouri regulator's recent approval of Ameren's (AEE-N, not covered) (link) wind projects, which would be very comparable to "Greening the Fleet", gives us confidence that the projects will proceed. After accounting for tax equity, we estimate the projects should add US$500m-US$600m to rate base in 2021. We assume that the wind farms are purchased in 1H/21 and reflected in customer rates in 2H/21.

Some funding work to do. Management plans to fund its capital plan with one-third free cash flow, one-third debt, and one-third equity (tax equity, DRIP, hybrid, ATM, issuances). Given its relatively smaller size and unregulated renewable assets (higher risk in the eyes of credit rating agencies), we believe the company would want to remain around 50/50 debt-to-equity and mid-teens FFO-to-debt. To fund its growth we have added US$250m of common equity issuances in each of 2020E and 2021E.

Emera (Sector Perform; $51.00 TP)

Florida drives Emera's 6% rate base growth. Emera's growth is largely driven by its Florida operations (TECO and Peoples Gas), which represent roughly two-thirds of Emera's go-forward capital plan. We forecast TECO's rate base growing at an 8% CAGR as it benefits not only from normal rate base growth but also from large generation investments to modernize Big Bend and in solar. Peoples Gas' rate base CAGR of 15% from 2018-2021E is also very strong as it stands to benefit from customer growth as well as greater connectivity. We also note that further growth is possible in Florida as Emera could add another 600 MW of solar at a cost of US$850m, once Big Bend is modernized.

Exhibit 2: Emera – Estimate Overview

Key Metrics		2018A	2019E	2020E	2021E
Adj. EBITDA	$M	2,442	2,640	2,690	2,856
YoY Growth	%	5%	8%	2%	6%
Adj. EPS (diluted)	$/shr	2.77	2.72	2.87	3.01
YoY Growth	%	13%	(2%)	5%	5%
FCFPS	$/shr	3.84	3.49	3.44	3.68
YoY Growth	%	87%	(9%)	(1%)	7%
DPS	$/shr	2.28	2.37	2.47	2.57
YoY Growth	%	7%	4%	4%	4%

Source: Company reports; Scotiabank GBM estimates.

Emera Maine sale improves funding situation. We have adjusted our model to reflect the sale of Emera Maine at an estimated price of $1.3b. This is slightly above management's general asset sale target of $0.6b-$1.3b. The sales price assumes a 9x EV/EBITDA, 1.3x rate base and 26x PE. This asset sale replaces the $0.6b of common equity we had previously included in our model in 2020. To fund the remainder of its capital plan we forecast Emera relying on its FCF, incremental debt, and $0.3b of hybrids as

well as $0.6b of DRIP proceeds. There is the potential that the Emera Maine sale could allow the company to reduce its reliance on the DRIP in 2021. We assume the sale closes in Q1/20 and we expect it to be slightly accretive versus our prior longer term estimates – however, the timing of the sale versus our prior timing of equity issuances lowers our 2020 EPS estimate by $0.02.

5% EPS growth in 2021. In 2021 Florida continues to be the key driver of growth for Emera. TECO will benefit from standard rate base growth, a full year contribution from its solar investments as well as increasing returns from its Big Bend Modernization project. In addition, we note that Emera continues to work on a number of projects (i.e. more solar) that could be additive to our 2021 estimate. We forecast EPS growth of 5%, which is slightly below its expected rate base growth of 6% as we see some continued de-levering (i.e. sale of Emera Maine in 2020) as being a minor headwind.

Fortis (Sector Perform; $51.00 TP)

7% rate base growth. Fortis expects a 7% rate base CAGR from 2018 to 2021. This steps down slightly to 6.3% if we extend the forecast horizon out to 2023. In 2021 we estimate 6% y/y rate base growth to ~$32b, which would be in line with management's expectations. Fortis' U.S. utilities (UNS, ITC, and to a lesser extent Central Hudson) are the largest drivers of this growth, and we believe these assets have a long runway of growth. In Canada, FortisBC Energy (gas) is also growing quickly given system replacement projects and system extensions.

Exhibit 3: Fortis – Estimate Overview

Key Metrics		2018A	2019E	2020E	2021E
Adj. EBITDA	$M	3,646	3,844	4,087	4,344
YoY Growth	%	3%	5%	6%	6%
Adj. EPS (diluted)	$/shr	2.47	2.64	2.83	3.00
YoY Growth	%	(2%)	7%	7%	6%
FCF/shr	$/shr	3.22	3.28	3.51	3.58
YoY Growth	%	(12%)	2%	7%	2%
DPS	$/shr	1.73	1.83	1.94	2.05
YoY Growth	%	6%	6%	6%	6%

Source: Company reports; Scotiabank GBM estimates.

Making 7% rate base growth look easy. We recently hosted members of Fortis' management team for institutional marketing. A key takeaway for us was how well positioned its existing utilities are to continue to generate above-average growth. We expect the company will continue to add projects to its capital plan in order to extend its outlook for 7% growth towards the middle of the next decade. This growth outlook, a highly achievable financing plan, and a low payout ratio make Fortis a core holding for many investors.

6% EPS growth in 2021. Our 2021 EPS estimate implies 6% y/y growth, which would be in line with that year's rate base growth. Over the next few years, Fortis' regulatory schedule is relatively straightforward. In the next few months, UNS will file a rate case for Tucson with rates in effect for 2H/20. The timing and outcome of this rate case could move our EPS estimate for 2021 slightly.

Funding plan – toughest part completed. The recently announced sale of the Waneta Expansion hydro project for $1b (25x EBITDA) fulfills the asset sale portion of Fortis' five-year funding plan. That said, management noted that if opportunities presented themselves at attractive valuations they would consider them. Beyond asset sales, the capital plan is expected to be funded with cash flow, DRIP proceeds, and some regulated debt. The company's ATM program could further support the funding plan if new projects are secured, though nothing appears imminent.

Hydro One (Sector Perform; $22.00)

5% rate base growth. Management expects ~5% rate base CAGR from 2018-2022. Even with recent regulatory decisions scaling back capex we are roughly in line with management's growth rate. Driving Hydro One's rate base growth is largely the replacement of aging infrastructure, to which there is little alternative.

6% EPS growth in 2021. We expect EPS growth to accelerate in 2021 as Hydro One's utilities should benefit from both solid rate base growth as well as improved returns on its assets. We estimate EPS growth of 6% in 2021, slightly higher than rate base growth that year as both Distribution and Transmission will be operating under incentive regulation regimes that could result in achieved ROEs being above allowed ROES.

Exhibit 4: Hydro One – Estimate Overview

Key Metrics		2018A	2019E	2020E	2021E
Adj. EBITDA	$M	2,225	2,295	2,427	2,601
YoY Growth	%	8%	3%	6%	7%
Adj. EPS (diluted)	$/shr	1.35	1.33	1.38	1.46
YoY Growth	%	16%	-1%	4%	6%
FCF/shr	$/shr	1.49	1.53	1.61	1.72
YoY Growth	%	(3%)	3%	5%	7%
DPS	$/shr	0.91	0.95	1.00	1.05
YoY Growth	%	5%	5%	5%	5%

Source: Company reports; Scotiabank GBM estimates.

Strong funding position. We expect Hydro One to fund its capital plan with free cash flow and incremental debt. The company does not have a dilutive DRIP program and it has limited amounts of hybrid securities. With a ~13% adj. FFO-to-adj. debt and 56% net debt-to-capitalization in 2020E, Hydro One has a very strong balance sheet. Given that we don't consider material M&A to be likely, we expect this strong balance sheet to persist.

Growth Continues in 2021

High-quality, low-risk growth. As outlined in Exhibit 5, we are introducing 2021 estimates for the utilities. Overall we forecast the group continuing to grow in the mid- to high-single digits in 2021, which would be similar to prior years. Looking beyond 2021E, we see similar growth rates as we expect the positive fundamentals that are driving rate base growth (transmission, generation, system improvements) to continue for a few more years. While customer rates are a natural governor of growth in rate base (and thus earnings), we note that one of the benefits of U.S. tax reform was lower overall customer bills. In addition, this utility growth is largely the sum of thousands of small to medium projects. Where there are large-scale projects, they are typically related to replacing or renewing legacy generating assets with lower-carbon options. As such, we don't see the same level of political or stakeholder opposition to these projects as we would with pipeline projects.

Exhibit 5: Utility Estimate Overview

	EPS			EPS Growth			CAGR	FCFPS			FCFPS Growth			CAGR	DPS			DPS Growth			CAGR
	2019E	2020E	2021E	2019E	2020E	2021E	'19-'21E	2019E	2020E	2021E	2019E	2020E	2021E	'19-'21E	2019E	2020E	2021E	2019E	2020E	2021E	'19-'21E
Utilities																					
Algonquin (US$)	0.66	0.73	0.79	13%	10%	9%	9%	0.67	0.74	0.77	(12%)	11%	5%	8%	0.55	0.61	0.67	10%	10%	10%	10%
Emera	2.72	2.87	3.01	(2%)	5%	5%	5%	3.49	3.44	3.68	(9%)	(1%)	7%	3%	2.37	2.47	2.57	4%	4%	4%	4%
Fortis	2.64	2.83	3.00	7%	7%	6%	7%	3.28	3.51	3.58	2%	7%	2%	4%	1.83	1.94	2.05	6%	6%	6%	6%
Hydro One	1.33	1.38	1.46	(1%)	4%	6%	5%	1.53	1.61	1.72	3%	5%	7%	6%	0.95	1.00	1.05	5%	5%	5%	5%
Average				*4%*	*7%*	*6%*	*7%*				*(4%)*	*5%*	*5%*	*5%*				*6%*	*6%*	*6%*	*6%*

Source: Company reports; Scotiabank GBM estimates.

Strong Growth North and South of the Border

Canadian utilities are U.S. utilities in disguise. Looking at our 2019-2021 estimates, we see the Canadian utilities growing at a slightly faster pace than the U.S. utilities covered by our Scotia Howard Weil colleague, Andrew Weisel (Exhibit 6). This is not surprising as the U.S. operations of the Canadian group are the largest drivers of growth. In fact, in 2021E, the U.S. operations represent the lion's share of the group's income, aside from the Ontario-centric Hydro One (Exhibit 7).

Exhibit 7: Business Mix – Geographic Breakdown

	Chg in FX		Metric	Unhedged Sensitivity		Notes
				$	%	
Utilities						
Algonquin	Estimates and target price are in U$.					~85% of operations
Emera	C$/US$	$0.05	EPS	$0.07	2%	~72% of operations
Fortis	C$/US$	$0.05	EPS	$0.07	3%	~60% of operations
Hydro One	C$/US$	$0.05	EPS	$0.00	0%	0% of operations a

Source: Company reports; Scotiabank GBM estimates.

Exhibit 6: Stronger Growth for the Canadian Utilities

	2019-2021E CAGR	
	EPS	DPS
Canadian Utilities		
AQN-T	9.4%	10.0%
EMA-T	5.2%	4.0%
FTS-T	6.6%	6.0%
H-T	4.9%	5.0%
Median	***5.9%***	***5.5%***
Mean	***6.5%***	***6.3%***
Regulated US Utilities		
LNT-N	5.6%	6.3%
AEP-N	5.7%	6.5%
BKH-N	6.6%	6.1%
CMS-N	7.4%	7.0%
ED-N	3.8%	3.5%
DUK-N	5.5%	3.3%
ETR-N	5.2%	3.3%
ES-N	5.8%	6.3%
FE-N	1.1%	3.8%
SO-N	2.8%	3.3%
WEC-N	6.5%	6.3%
Median	***5.6%***	***6.1%***
Mean	***5.1%***	***5.1%***
Diversified US Utilities		
D-N	4.7%	8.6%
DTE-N	5.3%	6.4%
EXC-N	1.5%	5.0%
NEE-N	7.7%	11.3%
PEG-N	5.5%	4.8%
Median	***5.3%***	***6.4%***
Mean	***5.0%***	***7.2%***
US Median	***5.5%***	***6.2%***
US Mean	***5.0%***	***5.7%***

Source: Company reports; Scotiabank GBM estimates.

All Eyes on Leverage

Leverage coming down. A common push-back we get on the Canadian utility space is how much debt the companies carry, though this generally relates to Fortis and Emera. While we agree that both these companies have elevated leverage metrics following recent acquisitions (ITC, TECO) and the impact of U.S. tax reform, we do note that their metrics are trending in the right direction.

But Canadian utilities *should* have higher leverage. A point often overlooked is that utilities in Canada have weaker credit metrics given their lower allowed ROEs and equity thicknesses. As illustrated in Exhibit 8, a Canadian utility should generate 11-12% FFO-to-debt as well as a 6x debt to EBITDA based on its prescribed capital structure. This would be significantly weaker than U.S. utilities with 15%+ FFO-to-debt metrics, though in the eyes of the credit rating agencies the two utilities would have similar risk profiles. We see Emera's and Fortis' FFO-to-debt moving towards 12% (Exhibit 9), though this would still be well below the US utility group that is closer to 15%.

Exhibit 8: Illustrative Utility Credit Metrics

	Canadian Utilities		US Utilities		
	NSPI	FortisBC Gas	TECO	ITC	UNS
Rate Base	1,000	1,000	1,000	1,000	1,000
Equity Thickness	40%	39%	54%	60%	50%
Allowed ROE (mid-point)	9.00%	8.75%	10.50%	11.00%	9.75%
Tax Rate	25%	25%	21%	21%	21%
Cash Tax Rate	5%	5%	5%	5%	5%
Interest Rate	4.5%	4.5%	4.5%	4.5%	4.5%
EBITDA	100	98	117	127	109
Depreciation	25	25	25	25	25
Interest	27	28	21	18	23
Taxes	12	11	15	18	13
Net Income	36	34	57	66	49
FFO	71	68	94	105	84
FFO-to-Debt	**11.9%**	**11.1%**	**20.4%**	**26.3%**	**16.8%**
Net debt to EBITDA	**6.0**	**6.3**	**3.9**	**3.2**	**4.6**

Source: Company reports; Scotiabank GBM estimates.

Exhibit 9: Utility Credit Overview

	Adj. Net Debt / EBITDA				Adj. FFO / Adj. Net Debt			DRIP Participation			EPS Payout Ratio		
	2018A	2019E	2020E	2021E	2019E	2020E	2021E	2019E	2020E	2021E	2019E	2020E	2021E
Utilities													
Algonquin (US$)	4.3x	4.7x	4.3x	4.3x	15.6%	17.0%	17.1%	25%	25%	25%	83%	83%	84%
Emera	6.5x	5.6x	5.7x	5.6x	12.5%	11.8%	12.2%	40%	40%	20%	87%	86%	85%
Fortis	6.7x	6.5x	6.4x	6.2x	11.2%	11.4%	11.6%	35%	35%	35%	69%	68%	68%
Hydro One	5.3x	5.7x	5.7x	5.6x	12.9%	13.0%	13.1%	0%	0%	0%	72%	73%	72%
Average	*5.7x*	*5.6x*	*5.5x*	*5.4x*	*13.1%*	*13.3%*	*13.5%*	*25%*	*25%*	*20%*	*78%*	*78%*	*77%*

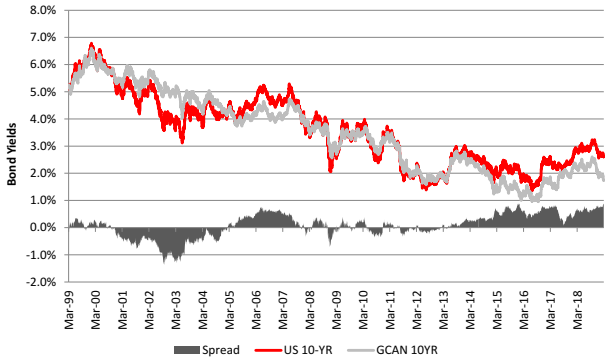
Source: Company reports; Scotiabank GBM estimates.

Canadian Utes Look Attractive Versus Their U.S. Peers

Utility valuations are tied to bond yields. The U.S. utilities under Scotia Howard Weil coverage have an average implied target 2021E P/E of 16.7x. Driving this is a multi-variable regression analysis with an adjusted R^2 of 0.85. We have re-created this analysis for the Canadian companies (see Appendix I). Not surprisingly, the R^2 is lower for the Canadian utilities at 0.75, which we attribute primarily to a smaller sample size as well as the utilities historically having some unregulated businesses (Fortis – properties, Emera – generation, Canadian Utilities – generation).

What matters more – U.S. or Canadian bond yields? Our analysis shows similar R^2 (~0.75) for regressions run with U.S. and Canadian bond yields. This is not surprising given that both yields are highly correlated. We often have discussions with investors on which yields matter most in determining valuations. This is especially important now given the recent divergence between U.S. and Canadian 10-year yields, with Canada trading at a ~85 bps discount (Exhibit 10). We are of the view that U.S. rates matter more for the Canadian utilities given: (1) their increasing U.S. asset bases, (2) increasing U.S. ownership of the shares, and (3) ability of most investors to own U.S. and Canadian yield instruments.

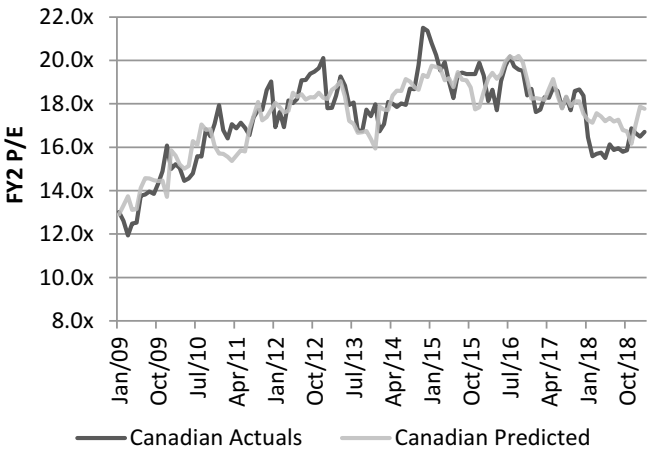
Exhibit 10: Canadian yields at a discount



Source: Bloomberg; Scotiabank GBM estimates.

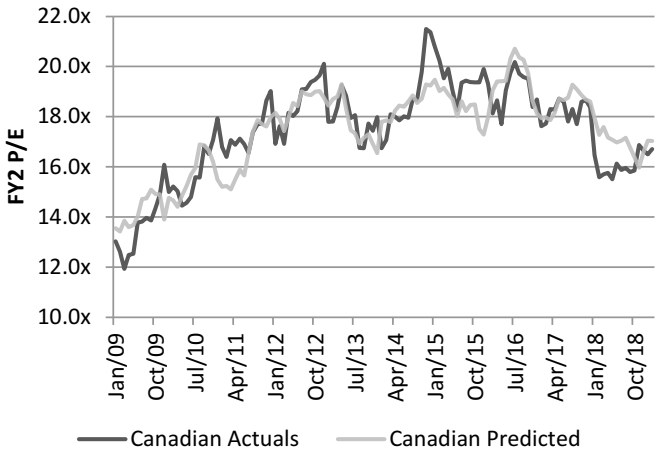
Fairly valued using U.S. yields – undervalued with Canadian. Our regression analysis implies that based on recent 10-year U.S. Treasury yields, Canadian utilities FY2 PE should be 17.3x, which is roughly in ine with where Emera and Fortis are trading on 2020E P/E. If we use Canadian rates instead, the model's FY2 PE increases to 18.2x. So the regressions show that if the utilities valuations are determined by Canadian yields they are undervalued, but they would be fairly valued using U.S. yields.

Exhibit 11: Utility P/Es – Regression with Canadian Yields



Source: Bloomberg; Scotiabank GBM.

Exhibit 12: Utility P/Es – Regression with U.S. Yields



Source: Bloomberg; Scotiabank GBM.

Moving up and rolling forward our target PEs. We now value the Canadian utilities based off of our 2021 EPS estimates (previously 2020), similar to how our colleague Andrew Weisel values the U.S. utilities. Our regression analysis and a forward view of bond yields from Scotia Economics imply a P/E of 16.2x if we use U.S. yields (3.1%) and 16.9x if we use Canadian yields (2.3%). Our targets are predicated on an average 16.5x P/E. This implies a slight compression in P/Es, relative to NTM levels, as bond yields rise. If bond yields stay where they are (U.S. 2.6% and Canada 1.75%) then we could see a ~1x increase (~6%) in our target multiples based on our sensitivity tables below.

Exhibit 13: Target Valuations

	Rating	Target Price			Target P/E		LT Avg.
		New	Prior	Delta	New	Old	P/E
AQN (US$)	SO	13.00	12.00	8%	16.75x	16.25x	20.2x
EMA	SP	51.00	46.00	11%	16.75x	15.75x	17.3x
FTS	SP	51.00	45.00	13%	17.00x	16.50x	17.7x
H	SP	22.00	21.00	5%	15.00x	15.00x	16.1x

Source: Company reports; Scotiabank GBM estimates.

Exhibit 14: Regression Sensitivity Analysis – Canadian Yields

Ute EPS LTG \ 10-year GOC yield	1.50%	1.75%	2.00%	2.30%	2.50%	2.75%	3.00%
2.0%	18.4x	17.9x	17.3x	16.6x	16.2x	15.7x	15.1x
3.0%	18.6x	18.0x	17.4x	16.8x	16.3x	15.8x	15.2x
4.1%	18.7x	18.2x	17.6x	16.9x	16.5x	15.9x	15.4x
5.0%	18.8x	18.3x	17.7x	17.1x	16.6x	16.1x	15.5x
6.0%	19.0x	18.4x	17.9x	17.2x	16.8x	16.2x	15.7x

Source: Scotiabank GBM estimates.

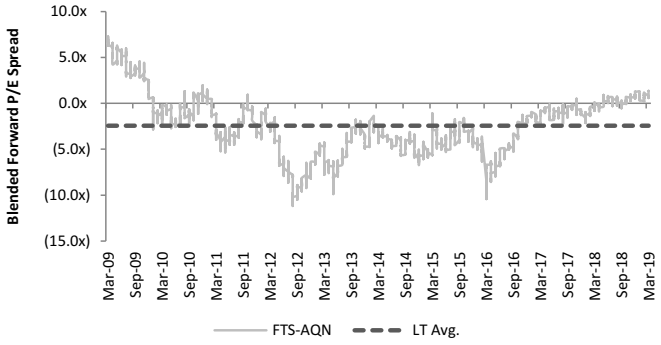
Exhibit 15: Regression Sensitivity Analysis – U.S. Yields

Ute EPS LTG \ 10-year US Treasury yield	2.50%	2.60%	2.75%	3.00%	3.10%	3.25%	3.5(
2.0%	17.3x	17.0x	16.7x	16.1x	15.9x	15.6x	15
3.0%	17.4x	17.1x	16.8x	16.3x	16.0x	15.7x	15
4.1%	17.5x	17.3x	16.9x	16.4x	16.2x	15.8x	15
5.0%	17.6x	17.4x	17.0x	16.5x	16.3x	15.9x	15
6.0%	17.7x	17.5x	17.2x	16.6x	16.4x	16.0x	15

Source: Scotiabank GBM estimates.

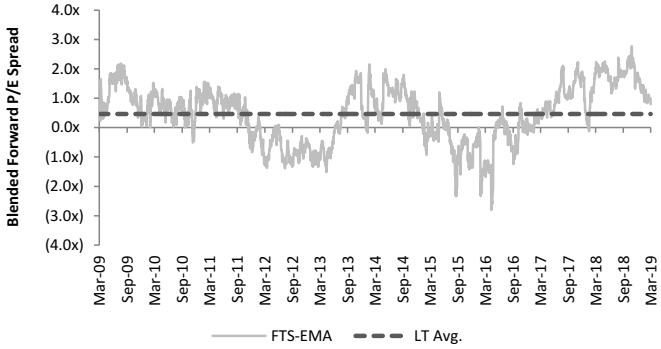
- **Algonquin:** Recently, Algonquin has traded in line with Fortis on a forward P/E basis. We attribute this to its above-average growth outlook, partially offset by a diverse asset base composed of smaller utilities, which normally would trade at a discount. Our 16.75x target P/E is a slight discount to Fortis as it implicitly assumes that Algonquin's growth could moderate beyond 2021.
- **Emera:** In recent years, Emera has traded at a fairly wide discount to Fortis. However, with greater clarity on the funding profile this discount has narrowed (faster than we expected). We believe that Emera should trade at a slight discount to Fortis to reflect its lower growth profile and higher payout ratio, which increases its reliance on the public markets.
- **Fortis:** Fortis remains the benchmark utility for many Canadian investors. We expect that it will continue to trade at a premium to the group, reflecting its strong growth profile, highly achievable funding plan, and track record of being a well-run utility. Our 17.0x would be a premium to the group.

Exhibit 16: Fortis–Algonquin P/E Spread



Source: Company reports; Scotiabank GBM estimates.

Exhibit 17: Fortis–Emera P/E Spread

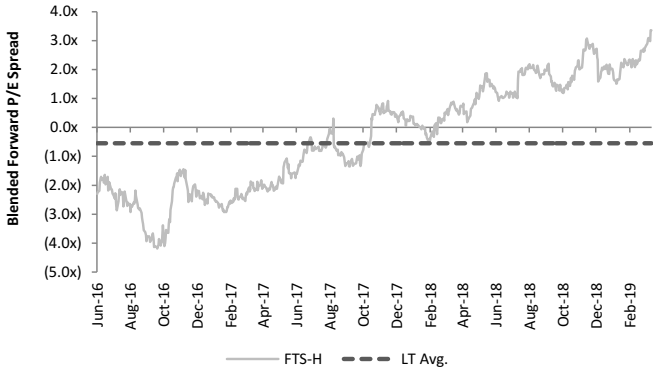


Source: Company reports; Scotiabank GBM estimates.

- **Hydro One:** Our $22 target price (up from $21) is based on a 15.0x multiple (no change). We expect Hydro One will continue to trade at a discount to the group given political and regulatory uncertainty. While our target price implies relatively healthy potential share price returns, this is offset by a higher risk profile.

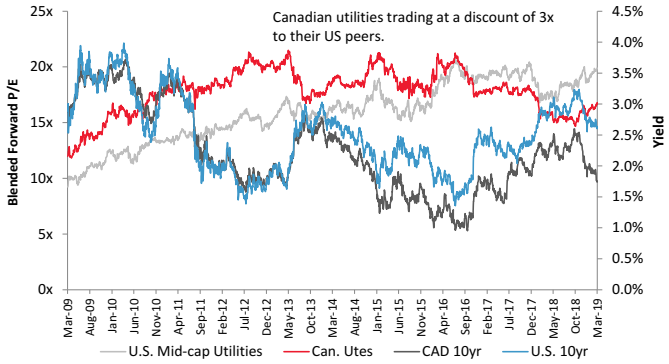
Canadian and U.S. valuations should converge. Historically, the Canadian utilities have traded at a premium to their mid-cap U.S. peers. We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view) as well as to strong earnings growth in part due to M&A. As shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a ~3x discount. We believe that this P/E discount should narrow and, as such, we consider the Canadian utilities to be relatively attractive versus their U.S. peers.

Exhibit 18: Fortis–Hydro P/E Spread



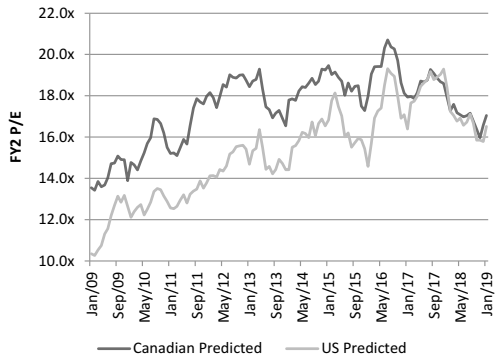
Source: Company reports; Scotiabank GBM estimates.

Exhibit 19: Canadian Premium Is Now a Discount



Note: Utes consist of AQN-T, CU-T, EMA-T, FTS-T, and H-T. U.S. Mid-cap Utilities consist of PNW-N, SCG-N, AEE-N, WEC-N, CMS-N, CNP-N, NI-N, GAS-N, and WR-N
Source: Bloomberg; Scotiabank GBM estimates.

Exhibit 20: Regressions Show Valuations Converging



Source: Bloomberg; Scotiabank GBM estimates.

Exhibit 21: Energy Infrastructure – Sector Overview and Recent Trading Multiples

	Ticker	Rating	Target Price	Total Return	Dividend Rate	Dividend Yield	Price 13-Mar-19	Shares O/S (m)	MC ($b)	EV ($b)	P/E ratios 2018A	2019E	2020E	2021E
Utilities														
Algonquin Power & Utilities Corp. (US$)	AQN-US	SO	$13.00	20.5%	$0.55	4.9%	$11.25	489	$5.5	$9.8	19.2x	17.0x	15.5x	14.2x
ATCO Ltd.	ACO.X-CA	n.a.	n.a.	n.a.	$1.62	3.6%	$45.40	115	$5.2	$18.8	14.6x	14.4x	13.9x	13.0x
Canadian Utilities Ltd.	CU-CA	n.a.	n.a.	n.a.	$1.69	4.7%	$36.17	274	$9.9	$21.1	16.1x	16.5x	15.9x	15.2x
Emera Inc.	EMA-CA	SP	$51.00	8.7%	$2.37	4.8%	$49.09	234	$11.5	$28.8	17.7x	18.0x	17.1x	16.3x
Fortis Inc.	FTS-CA	SP	$51.00	8.0%	$1.73	3.5%	$48.81	429	$20.9	$48.2	19.8x	18.5x	17.2x	16.3x
Hydro One Ltd.	H-CA	SP	$22.00	13.4%	$0.95	4.7%	$20.25	596	$12.1	$24.0	15.0x	15.2x	14.7x	13.8x
Utilities average (ex ACO)						***4.5%***					***17.6x***	***17.0x***	***16.1x***	***15.2x***
U.S. Regulated Utilities														
Alliant Energy Corp	LNT	SP	$45.00	-1.5%	$1.42	3.0%	$47.14	236	$11.1	$16.9	21.7x	20.9x	19.7x	18.6x
American Electric Power Company, Inc.	AEP	SP	$77.00	-4.2%	$2.68	3.2%	$83.18	493	$41.0	$65.0	21.1x	20.1x	18.9x	17.8x
Black Hills Corporation	BKH	SU	$62.00	-12.0%	$2.02	2.8%	$72.72	60	$4.4	$7.7	20.5x	21.2x	19.8x	18.6x
CMS Energy Corporation	CMS	SO	$54.00	0.4%	$1.53	2.8%	$55.30	283	$15.7	$25.8	23.7x	22.1x	20.6x	19.3x
Consolidated Edison, Inc.	ED	SU	$74.00	-9.7%	$2.96	3.5%	$85.18	321	$27.3	$44.3	19.7x	19.7x	18.7x	17.9x
DTE Energy Company	DTE	SO	$126.00	4.5%	$3.78	3.0%	$124.16	182	$22.6	$36.1	19.7x	19.9x	18.9x	17.6x
Duke Energy Corporation	DUK	SO	$92.00	5.7%	$3.71	4.1%	$90.56	727	$65.8	$121.5	19.2x	18.3x	17.3x	16.6x
Eversource Energy	ES	SU	$63.00	-7.7%	$2.14	3.0%	$70.60	317	$22.4	$36.7	21.5x	20.3x	19.2x	18.2x
Southern Company	SO	SP	$45.00	-8.4%	$2.40	4.6%	$51.73	1,035	$53.5	$104.6	16.9x	17.1x	16.5x	15.9x
WEC Energy Group Inc.	WEC	SO	$76.00	0.7%	$2.36	3.0%	$77.80	315	$24.5	$35.4	23.3x	22.1x	20.8x	19.6x
U.S. Regulated Utilities average						***3.3%***					***20.4x***	***20.0x***	***18.8x***	***17.8x***
U.S. Diversified Utilities														
Dominion Energy Inc	D	SP	$77.00	5.7%	$3.67	4.8%	$76.30	808	$61.7	$101.2	18.8x	18.1x	17.3x	16.4x
Entergy Corporation (UP&O only)	ETR	SP	$90.00	-1.4%	$3.64	3.8%	$95.01	190	$18.0	$35.3	13.0x	17.3x	17.0x	16.2x
Exelon Corporation	EXC	SO	$50.00	3.7%	$1.45	2.9%	$49.63	970	$48.1	$84.7	15.9x	15.8x	15.6x	15.8x
FirstEnergy Corp.	FE	SO	$41.00	2.2%	$1.52	3.7%	$41.62	530	$22.1	$41.2	16.1x	16.2x	16.6x	15.9x
NextEra Energy, Inc.	NEE	SP	$187.00	0.5%	$5.00	2.6%	$190.97	478	$91.3	$125.9	24.8x	22.7x	21.1x	19.6x
Public Service Enterprise Group Inc.	PEG	SP	$58.00	0.6%	$1.88	3.2%	$59.51	505	$30.1	$44.3	19.1x	18.3x	16.8x	16.3x
U.S. Diversified Utilities average						***3.6%***					***17.7x***	***18.0x***	***17.5x***	***16.8x***

Figures for Canadian companies in C$; figures for US companies in US$. U.S. Regulated and U.S. Diversified Utilities covered by Scotia Howard Weil Analyst Andrew Weisel, estimates reflect consensus.
Source: Company reports; Factset; Scotiabank GBM estimates.

Appendix I: Regression-Based PE Analysis

Our Scotia Howard Weil colleague Andrew Weisel uses a multi-variable regression-based P/E model to derive target multiples for his U.S. regulated utility coverage. We have recreated his model (with some modifications) for the Canadian utilities using data from the past 10 years. The first regression produced a best-fit model with an adjusted R-squared of 0.75:

FY2 P/E ratio = β0 + β1*(10yrGoC) + β2*(BBB spread) + β3*(S&P E/P) + β4*(Ute EPS LTG)

The variables are defined below:

- 10yrGoC = yield on 10-year Government of Canada generic bond
- BBB spread = difference between Canadian BBB yield and 10yrGoC
- S&P E/P = S&P 500 earnings yield for FY2
- Ute EPS LTG = median FY2 y/y EPS growth for Canadian utilities

We then did a second regression using U.S. yields instead of Canadian yields of which the model also had an adjusted R-squared of .75:

FY2 P/E ratio = β0 + β1*(10yrUS) + β2*(Baa spread) + β3*(S&P E/P) + β4*(Ute EPS LTG)

New variables:

- 10yrUS = yield on 10-year U.S. Treasury bill
- Baa spread = difference between U.S. Baa yield and 10yrUS

We note that to reflect market valuation, we use the earnings yield for the S&P 500 rather than the TSX because the latter is too heavily bank/oil-focused for the purposes of our valuation.

Exhibit 22: Regression Results – Canadian Yields

Input	Current
10-yr GOC yield	1.8%
BBB spread	1.8%
Market valuation (S&P FY2 PE)	15.0x
Ute EPS LTG	4.1%
Predicted Utility P/E2	**18.1x**
Current Utility P/E2	17.1x
Upside	**6.1%**

Source: Bloomberg, Scotiabank GBM estimates.

Exhibit 23: Regression Results – U.S. Yields

Input	Current
10-yr US Treasury yield	2.6%
Baa spread	2.3%
Market valuation (S&P FY2 PE)	15.0x
Ute EPS LTG	4.1%
Predicted Utility P/E2	**17.3x**
Current Utility P/E2	17.1x
Upside	**1.0%**

Source: Bloomberg, Scotiabank GBM estimates.

Appendix II: Summary Models

Exhibit 24: Algonquin – Summary Model

Algonquin - Trading Stats (US$)					Year-end Dec. 31.
Recent Price	$/shr	11.25	Dividend (NTM)	$/shr	0.55
Shares O/S	M	488.9	Dividend Yield (NTM)	%	4.9%
Market Cap	$M	5,500			
Net Debt & Other	$M	4,322			
EV	$M	9,822			

Key Metrics		2017A	2018A	2019E	2020E	2021E
Adj. EBITDA	$M	682	747	830	912	1,019
YoY Growth	%		10%	11%	10%	12%
Adj. EBITDA (Ex. HLBV; Inc. PAYGO)	$M	657	675	775	854	950
YoY Growth	%		3%	15%	10%	11%
Adj. EPS (diluted)	$/shr	0.56	0.59	0.66	0.73	0.79
YoY Growth	%		4%	13%	10%	9%
FCF/shr	$/shr	0.49	0.75	0.67	0.74	0.77
YoY Growth	%		53%	(12%)	11%	5%
DPS	C$/shr	0.46	0.50	0.55	0.61	0.67
YoY Growth	%		10%	10%	10%	10%

Valuation & Ratios		2017A	2018A	2019E	2020E	2021E
EV/Adj. EBITDA	x	12.8x	13.1x	12.8x	12.1x	11.4x
P/E	x	20.0x	19.2x	17.0x	15.5x	14.2x
FCF Yield	%	4.4%	6.7%	5.9%	6.5%	6.9%
Dividend Yield	%	4.0%	4.5%	4.9%	5.4%	5.9%
Net Debt to EBITDA	x	4.6x	4.3x	4.7x	4.3x	4.3x
Net Debt to Capitalization	%	47%	45%	47%	46%	46%
Payout Ratio (FCF)	%	92%	67%	83%	82%	86%
Payout Ratio (EPS)	%	81%	85%	83%	83%	84%
ROE	%	10.4%	0.0%	0.0%	0.0%	0.0%

Income Statement		2017A	2018A	2019E	2020E	2021E
Generation	$M	193	249	321	345	394
Liberty Utilities	$M	541	551	565	625	684
Operating Earnings	$M	734	800	886	969	1,078
Admin & Other	$M	(52)	(53)	(56)	(57)	(59)
Depreciation	$M	(252)	(261)	(274)	(294)	(332)
Interest	$M	(129)	(151)	(175)	(181)	(200)
Taxes	$M	(73)	(51)	(38)	(44)	(39)
NCI	$M	(2)	9	(2)	(2)	(2)
Preferred Share Dividends	$M	(8)	(8)	(11)	(15)	(15)
Net Income	$M	218	273	330	376	431

Quarterly Forecast		Q1/18A	Q2/18A	Q3/18A	Q4/18A
Generation	$M	75	52	44	79
Liberty Utilities	$M	161	122	135	133
Operating Earnings	$M	236	174	179	212
Adj. EBITDA	$M	223	160	164	197
EPS (diluted)	$/shr	0.23	0.10	0.10	0.14
FCF/shr	$/shr	0.32	0.14	0.15	0.15
DPS	C$/shr	0.12	0.13	0.13	0.13

Balance Sheet		2017A	2018A	2019E	2020E	2021E
Cash	$M	43	47	5	56	55
Other Current Assets	$M	455	445	445	445	445
PP&E	$M	6,305	6,394	7,289	7,746	8,505
Other LT Assets	$M	1,594	2,504	2,504	2,504	2,504
Total Assets	$M	8,397	9,389	10,243	10,751	11,509
LT Debt - Current Portion	$M	12	13	13	13	13
Other Current Liabilities	$M	552	486	505	505	505
LT Debt	$M	3,067	3,324	3,824	3,974	4,374
Other LT Liabilities	$M	1,405	1,528	1,547	1,569	1,583
Total Liabilities	$M	5,036	5,350	5,888	6,060	6,475
NCI	$M	644	861	824	787	749
APUC Shareholders Equity	$M	2,717	3,178	3,530	3,904	4,284
Total Liabilities & Equity	$M	8,397	9,389	10,243	10,751	11,509

Cash Flow Analysis		2017A	2018A	2019E	2020E	2021E
Cash from Operations	$M	356	530	600	670	744
Cash from Investing	$M	(593)	(1,455)	(1,159)	(740)	(1,080)
Cash from Financing	$M	199	932	498	121	335
Adjustments due to FX	$M	(3)	(1)	-	-	-
Change in Cash	$M	(41)	6	(61)	51	(1)
Issue of common shrs. (inc DRIP)	$M	480	474	118	326	338
Change in preferred shares	$M	-	-	200	-	-
Acquisitions	$M	(1,600)	-	(379)	-	-
Capital expenditures	$M	(575)	(466)	(780)	(740)	(1,080)
Depreciation	$M	256	281	274	294	332
Adjusted FFO	$M	473	554	600	670	744
Pref. Share Dividends	$M	(8)	(8)	(11)	(15)	(15)
Distribution from (to) NCI	$M	(3)	(9)	(37)	(37)	(37)
Maintenance Capex + Other	$M	(273)	(189)	(223)	(241)	(275)
Free Cash Flow	$M	189	348	329	377	418

Business Mix (Operating Earnings)		2017A	2018A	2019E	2020E	2021E
Electrical Utility	%	57%	21%	20%	20%	20%
Gas Utility	%	15%	8%	9%	10%	9%
Water & Other Utilities	%	9%	35%	35%	35%	35%
Power	%	19%	36%	36%	36%	37%

Geographic Mix (Operating Earnings)		2017A	2018A	2019E	2020E	2021E
Canada	%	12%	12%	13%	15%	14%
U.S.	%	88%	88%	87%	85%	86%

Source: Company reports; Scotiabank GBM estimates.

Exhibit 25: Emera – Summary Model

Emera - Trading Stats												*Dec. 31 year-end.*
Recent Price	$/shr	49.09				Dividend (NTM)	$/shr	2.37				
Shares O/S	M	234				Dividend Yield (NTM)	%	4.8%				
Market Cap	$M	11,493				Dividend (recent)	$/shr	2.28				
Net Debt & Other	$M	17,270				Dividend Yield (Recent)	%	4.6%				
EV	$M	28,763										

Key Metrics		2017A	2018A	2019E	2020E	2021E	Valuation & Ratios		2017A	2018A	2019E	2020E	2021E
Adj. EBITDA	$M	2,335	2,442	2,640	2,690	2,856	EV/Adj. EBITDA	x	11.4x	11.8x	10.6x	10.7x	10.3x
YoY Growth	%	47%	5%	8%	2%	6%	P/E	x	20.0x	17.7x	18.0x	17.1x	16.3x
Adj. EPS (diluted)	$/shr	2.45	2.77	2.72	2.87	3.01	FCF Yield	%	4.2%	7.8%	7.1%	7.0%	7.5%
YoY Growth	%	1%	13%	(2%)	5%	5%	Dividend Yield	%	4.3%	4.6%	4.8%	5.0%	5.2%
FCFPS	$/shr	2.05	3.84	3.49	3.44	3.68							
YoY Growth	%	(25%)	87%	(9%)	(1%)	7%	Net Debt to Adj. EBITDA	x	6.1x	6.5x	5.6x	5.7x	5.6x
DPS	$/shr	2.13	2.28	2.37	2.47	2.57	Net Debt to Capitalization	%	60%	60%	56%	56%	56%
YoY Growth	%	7%	7%	4%	4%	4%	FFO to Net Debt	%	9.6%	11.9%	12.5%	11.8%	12.2%
							Payout Ratio (FCF)	%	104%	60%	68%	72%	70%
							Payout Ratio (EPS)	%	87%	82%	87%	86%	85%
							ROE	%	8.7%	9.4%	8.6%	8.7%	8.7%

Income Statement		2017A	2018A	2019E	2020E	2021E	Quarterly Forecast		Q1/18A	Q2/18A	Q3/18A	Q4/18A
NSPI	$M	129	131	136	142	146	NSPI	$M	65	23	15	28
TECO	$M	382	428	484	554	599	TECO	$M	90	97	140	101
Maine	$M	46	44	48	13	-	Maine	$M	10	6	17	11
Caribbean	$M	31	45	52	55	57	Caribbean	$M	5	12	14	14
Energy	$M	24	120	45	25	25	Energy	$M	55	2	19	44
Corp. & Other	$M	(88)	(120)	(119)	(91)	(83)	Corp. & Other	$M	(23)	(29)	(37)	(31)
Adj. Net Income	$M	524	648	647	697	744	Adj. Net Income	$M	202	111	168	167
							Adj. EBITDA	$M	641	529	635	606
							EPS (diluted)	$/shr	0.87	0.48	0.71	0.71
							FCFPS	$/shr	0.95	0.46	1.26	1.16
							DPS	$/shr	0.57	0.57	0.57	0.59

Balance Sheet		2017A	2018A	2019E	2020E	2021E	Cash Flow Analysis		2017A	2018A	2019E	2020E	2021E
Cash	$M	438	372	240	90	70	Cash from Operations	$M	1,193	1,690	1,745	1,726	1,843
Other Current Assets	$M	2,088	2,410	2,410	2,410	2,410	Cash from Investing	$M	(1,739)	(2,190)	(255)	(2,074)	(1,754)
PP&E	$M	16,995	19,539	20,979	21,960	22,778	Cash from Financing	$M	593	344	(1,622)	198	(108)
Other LT Assets	$M	9,250	9,993	7,799	8,267	8,209	Adjustments due to FX	$M	(13)	25	-	-	-
Total Assets	$M	28,771	32,314	31,428	32,727	33,467	Change in Cash	$M	34	(131)	(132)	(150)	(20)
LT Debt - Current Portion	$M	1,982	2,305	1,705	2,705	3,105	Issue of common shares (inc DRIP)	$M	682	10	224	236	175
Other Current Liabilities	$M	1,964	2,248	2,248	2,248	2,248	Change in preferred shares	$M	-	291	300	-	-
LT Debt	$M	13,140	14,292	13,352	12,962	12,962	Acquisitions	$M	-	-	-	-	-
Other LT Liabilities	$M	4,504	5,111	5,111	5,111	5,111	Capital expenditures	$M	(287)	(346)	(562)	(596)	(631)
Total Liabilities	$M	21,590	23,956	22,416	23,026	23,426	Depreciation	$M	851	928	921	923	937
NCI	$M	92	41	41	41	41							
Total Shareholders Equity	$M	7,089	8,317	8,971	9,660	10,000	CFO before changes in WC	$M	1,297	1,806	1,745	1,726	1,843
Total Liabilities & Equity	$M	28,771	32,314	31,428	32,727	33,467	Adjustments	$M	-	7	-	-	-
							Pref. Share Dividends and AFUDC	$M	(19)	(17)	(6)	10	(26)
							Maintenance Capex	$M	(841)	(902)	(913)	(904)	(912)
							Free Cash Flow	$M	437	894	826	832	904

Business Mix (of Earnings)		2017A	2018A	2019E	2020E	2021E	Geographic Mix (of Earnings)		2017A	2018A	2019E	2020E	2021E
NSPI	%	21%	17%	18%	18%	18%	Canada	%	21%	17%	18%	18%	18%
TECO	%	62%	56%	63%	70%	72%	U.S.	%	74%	77%	75%	75%	75%
Maine	%	8%	6%	6%	2%	0%	Caribbean	%	5%	6%	7%	7%	7%
Pipelines	%	0%	0%	0%	0%	0%							
Caribbean	%	5%	6%	7%	7%	7%							
Energy	%	4%	16%	6%	3%	3%							

Source: Company reports; Scotiabank GBM estimates.

Exhibit 26: Fortis – Summary Model

Fortis - Trading Stats												Year-end Dec. 31
Recent Price	$/shr	48.81					Dividend	$/shr	1.73			
Shares O/S	M	429					Dividend Yield	%	3.5%			
Market Cap	$M	20,920										
Net Debt & Other	$M	27,299										
EV	$M	48,219										

Key Metrics		2017A	2018A	2019E	2020E	2021E	Valuation & Ratios		2017A	2018A	2019E	2020E	2021E
Adj. EBITDA	$M	3,523	3,646	3,844	4,087	4,344	EV/Adj. EBITDA	x	11.8x	12.2x	11.8x	11.4x	11.0x
YoY Growth	%	54%	3%	5%	6%	6%	P/E	x	19.4x	19.8x	18.5x	17.2x	16.3x
Adj. EPS (diluted)	$/shr	2.52	2.47	2.64	2.83	3.00	FCF Yield	%	7.5%	6.6%	6.7%	7.2%	7.3%
YoY Growth	%	10%	(2%)	7%	7%	6%	Dividend Yield	%	3.3%	3.5%	3.7%	4.0%	4.2%
FCF/shr	$/shr	3.65	3.22	3.28	3.51	3.58							
YoY Growth	%	44%	(12%)	2%	7%	2%	Net Debt to EBITDA	x	6.2x	6.7x	6.5x	6.4x	6.2x
DPS	$/shr	1.63	1.73	1.83	1.94	2.05	Net Debt to Capitalization	%	55%	56%	56%	56%	56%
YoY Growth	%	6%	6%	6%	6%	6%	Payout Ratio (FCF)	%	45%	54%	56%	55%	57%
							Payout Ratio (EPS)	%	64%	70%	69%	68%	68%
							ROE	%	7%	7%	7%	8%	8%

Income Statement		2017A	2018A	2019E	2020E	2021E	Quarterly Forecast		Q1/18A	Q2/18A	Q3/18A	Q4/18A
UNS Energy	$M	264	293	285	317	339	UNS Energy	$M	50	81	135	27
Central Hudson	$M	72	74	88	103	119	Central Hudson	$M	21	12	17	24
ITC	$M	363	361	385	409	441	ITC	$M	86	86	97	92
FortisBC Energy (Gas)	$M	154	155	171	177	183	FortisBC Energy (Gas)	$M	98	7	(22)	72
Alberta & BC Utilities (Electric)	$M	175	176	184	193	201	Alberta & BC Utilities (Electric)	$M	43	47	51	35
Other Electric Utilities	$M	98	105	141	155	165	Other Electric Utilities	$M	18	35	30	22
Infrastructure	$M	88	66	60	53	53	Infrastructure	$M	18	20	12	16
Non-Regulated Non-Utility	$M	-	-	-	-	-	Non-Regulated Non-Utility	$M	-	-	-	-
Corporate and Other	$M	(167)	(180)	(174)	(164)	(164)	Corporate and Other	$M	(41)	(48)	(44)	(47)
Adj. Net Income	$M	1,047	1,050	1,140	1,242	1,337	Adj. Net Income	$M	293	240	276	241
							Adj. EBITDA	$M	900	906	930	901
							EPS (diluted)	$/shr	0.69	0.57	0.65	0.56
							FCF/shr	$/shr	0.89	0.79	0.95	0.59

Balance Sheet		2017A	2018A	2019E	2020E	2021E	Cash Flow Analysis		2017A	2018A	2019E	2020E	2021E
Cash	$M	327	332	296	226	201	Cash from Operations	$M	2,756	2,604	2,846	3,038	3,167
Other Current Assets	$M	1,880	2,163	2,163	2,163	2,163	Cash from Investing	$M	(3,025)	(3,252)	(2,780)	(3,425)	(3,255)
PP&E	$M	32,410	36,274	38,438	40,204	41,707	Cash from Financing	$M	339	644	(102)	316	63
Other LT Assets	$M	13,205	14,282	14,302	14,331	14,363	Adjustments due to FX	$M	(12)	9	-	-	-
Total Assets	$M	47,822	53,051	55,199	56,924	58,434	Change in Cash	$M	58	5	(36)	(71)	(25)
LT Debt - Current Portion	$M	705	926	926	926	926	Issue of common shr. (inc DRIP)	$M	809	357	274	294	317
Other Current Liabilities	$M	2,799	3,326	4,180	4,079	3,969	Change in preferred shares	$M	-	-	-	-	-
LT Debt	$M	20,691	23,159	23,729	24,766	25,601	Acquisitions or sales	$M	102	106	950	-	-
Other LT Liabilities	$M	8,624	9,107	9,107	9,107	9,107	Capital expenditures	$M	(3,024)	(3,218)	(3,730)	(3,425)	(3,255)
Total Liabilities	$M	32,819	36,518	37,942	38,878	39,603	Depreciation	$M	1,179	1,243	1,373	1,441	1,513
Preferred Shares	$M	1,623	1,623	1,623	1,623	1,623							
Shareholders Equity	$M	13,380	14,910	15,634	16,424	17,208	CFO before WC	$M	2,853	2,706	2,846	3,038	3,167
Total Liabilities & Equity	$M	47,822	53,051	55,199	56,924	58,434	Pref. Share Dividends	$M	(174)	(66)	(65)	(65)	(65)
							Other	$M	-	-	-	-	-
							Maintenance Capex	$M	(1,163)	(1,271)	(1,364)	(1,434)	(1,506)
							Free Cash Flow	$M	1,516	1,369	1,417	1,539	1,596

Business Mix (Operating Earnings)		2017A	2018A	2019E	2020E	2021E	Geographic Mix (of Earnings)		2017A	2018A	2019E	2020E	2021E
Electric Utility	%	78%	80%	80%	81%	82%	Canada	%	41%	40%	40%	39%	38%
Gas Utility	%	15%	15%	15%	15%	14%	U.S.	%	56%	57%	55%	56%	57%
Power & Other	%	7%	5%	5%	4%	4%	Other	%	3%	3%	5%	5%	5%

Source: Company reports; Scotiabank GBM estimates.

Exhibit 27: Hydro One – Summary Model

Hydro One - Trading Stats					Year-end Dec. 31
Recent Price	$/shr	20.25	Dividend (NTM)	$/shr	0.95
Shares O/S	M	596	Dividend Yield	%	4.7%
Market Cap	$M	12,068	Dividend (Cur)	$/shr	0.91
Net Debt & Other	$M	11,966	Dividend Yield	%	4.5%
EV	$M	24,034			

Key Metrics		2017A	2018A	2019E	2020E	2021E
Adj. EBITDA	$M	2,066	2,225	2,295	2,427	2,601
YoY Growth	%	0%	8%	3%	6%	7%
Adj. EPS (diluted)	$/shr	1.16	1.35	1.33	1.38	1.46
YoY Growth	%	(4%)	16%	-1%	4%	6%
FCF/shr	$/shr	1.54	1.49	1.53	1.61	1.72
YoY Growth	%	6%	(3%)	3%	5%	7%
DPS	$/shr	0.87	0.91	0.95	1.00	1.05
YoY Growth	%	4%	5%	5%	5%	5%

Valuation & Ratios		2017A	2018A	2019E	2020E	2021E
EV/Adj. EBITDA	x	11.4x	10.8x	11.0x	10.7x	10.3x
P/E	x	17.4x	15.0x	15.2x	14.7x	13.8x
FCF Yield	%	7.6%	7.4%	7.5%	7.9%	8.5%
Dividend Yield	%	4.3%	4.5%	4.7%	4.9%	5.2%
Net Debt to EBITDA	x	5.3x	5.3x	5.7x	5.7x	5.6x
Net Debt to Capitalization	%	51%	51%	55%	56%	56%
Payout Ratio (FCF)	%	57%	61%	63%	62%	61%
Payout Ratio (EPS)	%	75%	67%	72%	73%	72%
ROE	%	7.1%	8.1%	7.9%	8.1%	8.4%

Income Statement		2017A	2018A	2019E	2020E	2021E
Distribution	$M	898	921	1,000	1,037	1,102
Transmission	$M	1,203	1,345	1,336	1,434	1,545
Avista	$M	-	-	-	-	-
Other	$M	(35)	(41)	(41)	(44)	(47)
Total EBITDA	$M	2,066	2,225	2,295	2,427	2,601
Depreciation & Amortization	$M	817	837	886	942	1,001
Financing Charges	$M	420	426	451	475	524
Tax Expenses	$M	111	131	139	162	178
Net Income to NCI	$M	6	6	6	6	6
Preferred Dividends	$M	18	18	18	18	18
Adj. Net Income	$M	694	807	795	825	876

Quarterly Forecast		Q1/18A	Q2/18A	Q3/18A	Q4/18A
Distribution	$M	249	222	220	230
Transmission	$M	316	335	398	296
Avista	$M	-	-	-	-
Other	$M	(10)	(10)	(16)	(5)
Total EBITDA	$M	555	547	602	521
Adj. EBITDA	$M	555	547	602	515
EPS (diluted)	$/shr	0.35	0.32	0.38	0.29
AFFO/shr	$/shr	0.42	0.36	0.41	0.29
DPS	$/shr	0.22	0.23	0.23	0.23

Balance Sheet		2017A	2018A	2019E	2020E	2021E
Cash	$M	25	483	42	27	70
Other Current Assets	$M	994	1,008	1,029	1,059	1,089
PP&E	$M	19,947	20,687	21,654	22,714	23,826
Other LT Assets	$M	4,735	4,264	4,141	3,998	3,842
Total Assets	$M	25,701	26,442	26,866	27,798	28,826
LT Debt - Current Portion	$M	752	731	731	731	731
Other Current Liabilities	$M	2,475	2,704	2,215	2,215	2,215
LT Debt	$M	9,315	9,978	10,853	11,578	12,378
Other LT Liabilities	$M	2,906	2,519	2,499	2,479	2,459
Total Liabilities	$M	15,448	15,932	16,298	17,003	17,783
Non-Controlling Interest (NCI)	$M	72	70	64	58	52
Total Shareholders Equity	$M	10,253	10,510	10,568	10,795	11,043
Total Liabilities & Equity	$M	25,701	26,442	26,866	27,798	28,826

Cash Flow Analysis		2017A	2018A	2019E	2020E	2021E
Cash from Operations	$M	1,716	1,575	1,530	1,771	1,895
Cash from Investing	$M	(1,540)	(1,516)	(1,741)	(1,890)	(2,001)
Cash from Financing	$M	(201)	399	(231)	104	149
Change in Cash	$M	(25)	458	(441)	(15)	43
CFO before changes in WC	$M	1,603	1,598	1,668	1,771	1,895
Pref. Share dividends	$M	(18)	(18)	(18)	(18)	(18)
Distributions to NCI	$M	(6)	(8)	(6)	(6)	(6)
Maintenance Capex	$M	(665)	(685)	(734)	(790)	(849)
Free Cash Flow	$M	914	887	910	958	1,022

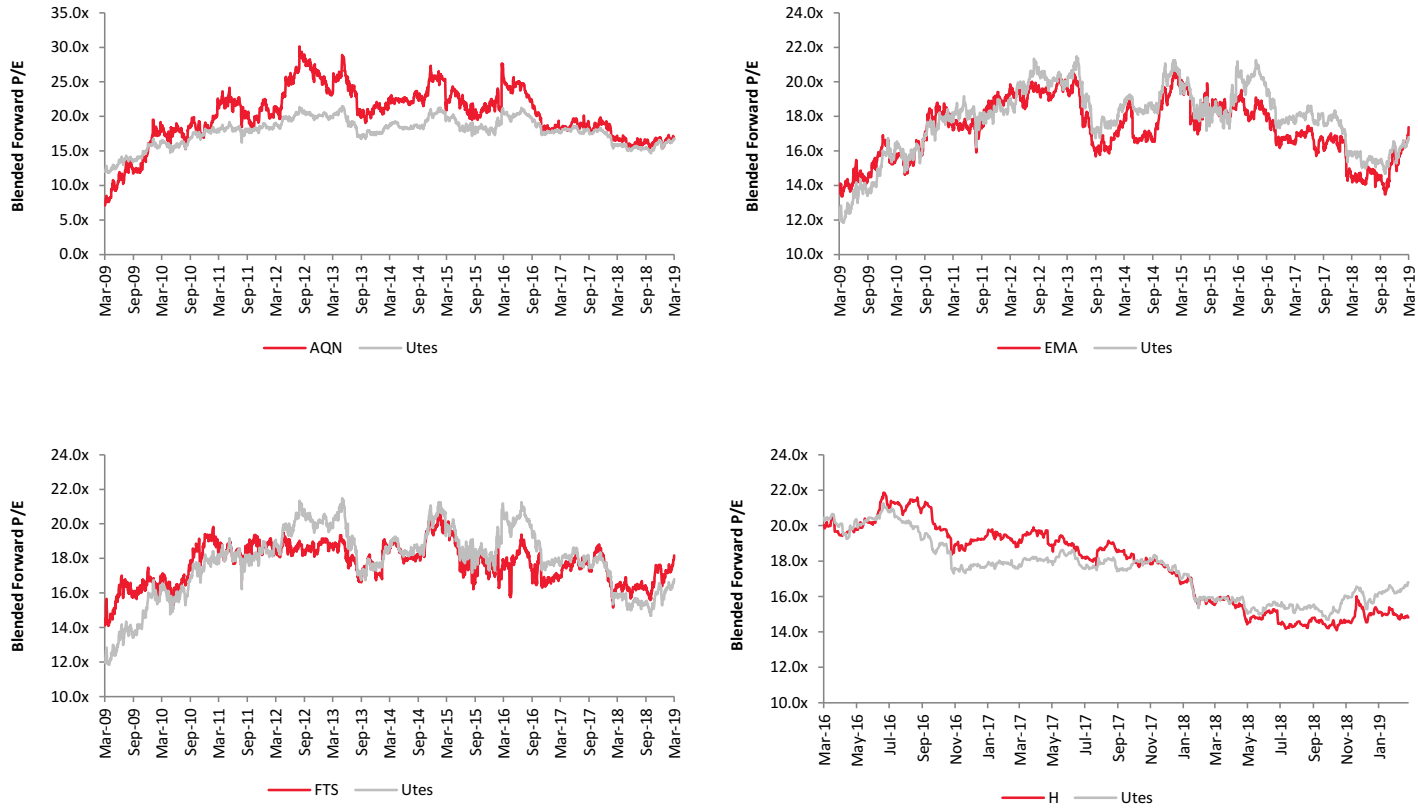
Business Mix (of EBITDA)		2017A	2018A	2019E	2020E	2021E
Distribution - Legacy	%	43%	41%	43%	42%	42%
Transmission - Legacy	%	57%	59%	57%	58%	58%

Geographic Mix (of EBITDA)		2017A	2018A	2019E	2020E	2021E
Ontario	%	100%	100%	100%	100%	100%

Source: Company reports; Scotiabank GBM estimates.

Appendix III: Long-Term Valuation Charts

Exhibit 28: Forward P/E Valuations for AQN, EMA, FTS, and H



Source: Bloomberg; Scotiabank GBM estimates.

Pertinent Data and Revisions

	Price	Rating	1-Yr. Target	1-Yr. Return
AQN-N	US$11.23	SO	US$13.00	20.7%
EMA-T	C$49.00	SP	C$51.00	8.9%
FTS-T	C$48.96	SP	C$51.00	7.7%
H-T	C$20.42	SP	C$22.00	12.4%

Algonquin Power & Utilities Corp. (AQN-N;US$11.23)

Key Risks: Interest rates; FX; hydrology and wind resource; regulated ROE; power prices

	New	Old
1-Yr. Target	US$13.00	US$12.00
Valuation	16.75x 2021E P/E Multiple	16.25x 2020E P/E Multiple

Emera Incorporated (EMA-T;C$49.00)

Key Risks: Interest rates; regulated ROEs; rate cases; growth projects; environmental legislation; power and capacity prices; access to and cost of capital.

	New	Old
1-Yr. Target	C$51.00	C$46.00
Key Data	Adj EPS19E: C$2.72	Adj EPS19E: C$2.74
	Adj EPS20E: C$2.87	Adj EPS20E: C$2.89
Valuation	16.75x 2021E P/E Multiple	15.75x 2020E P/E Multiple

Fortis Inc. (FTS-T;C$48.96)

Key Risks: Interest rates; rate base growth; regulated ROE; acquisitions; regulatory

	New	Old
1-Yr. Target	C$51.00	C$45.00
Key Data	Adj EPS20E: C$2.83	Adj EPS20E: C$2.85
Valuation	17.00x 2021E P/E Multiple	16.00x 2020E P/E Multiple

Hydro One Limited (H-T;C$20.42)

Key Risks: Interest rates; rate base growth; regulated ROE; acquisitions; regulatory

	New	Old
1-Yr. Target	C$22.00	C$21.00
Valuation	15.0x 2021E P/E Multiple	15.0x 2020E P/E Multiple

Appendix A: Important Disclosures

Company	Disclosures (see legend below)*
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American Electric Power Company, Inc.	G, U
Black Hills Corporation	G, I, N1, U
Consolidated Edison, Inc.	G, I, N1, U
Dominion Energy, Inc.	G, J, N1, N2, U, V19
DTE Energy Company	G, I, N1, U
Duke Energy Corporation	G, I, J, N1, U, V19
Emera Incorporated	G, HH, I, O3, U, VS0543
Entergy Corporation	G, I, N1, U
Exelon Corporation	V19, VS0547
FirstEnergy Corp.	G, U, VS0548
Fortis Inc.	G, HH, I, N1, O3, U
Hydro One Limited	G, HH, I, U
NextEra Energy, Inc.	V19, VS0546
Public Service Enterprise Group Incorporated	G, I, N1, U
The Southern Company	G, I, J, N1, N2, U, V19

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Algonquin Power & Utilities Corp. (AQN-N) as of March 15, 2019 (in USD)

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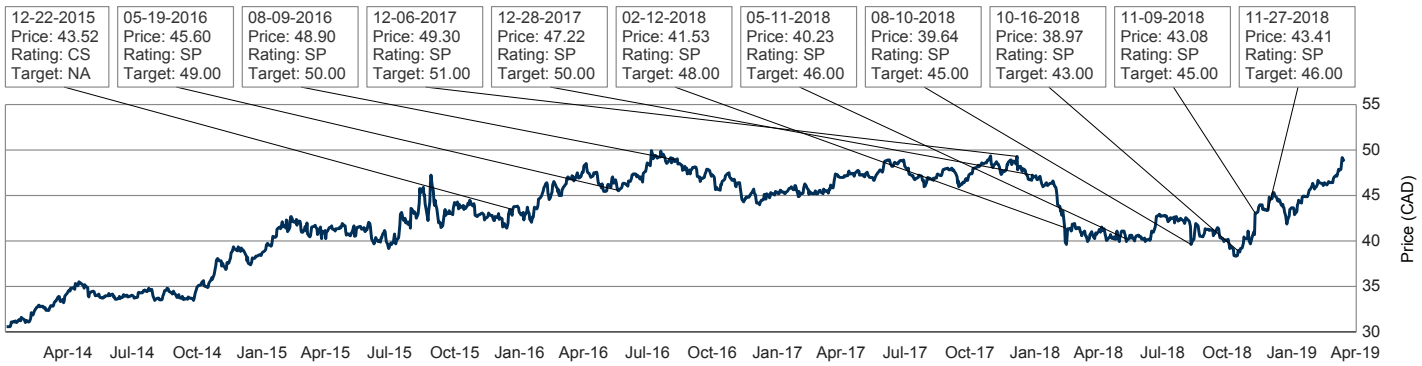
Source: Scotiabank GBM estimates/Scotia Howard Weil estimates; FactSet.

Emera Incorporated (EMA-T) as of March 15, 2019 (in CAD)

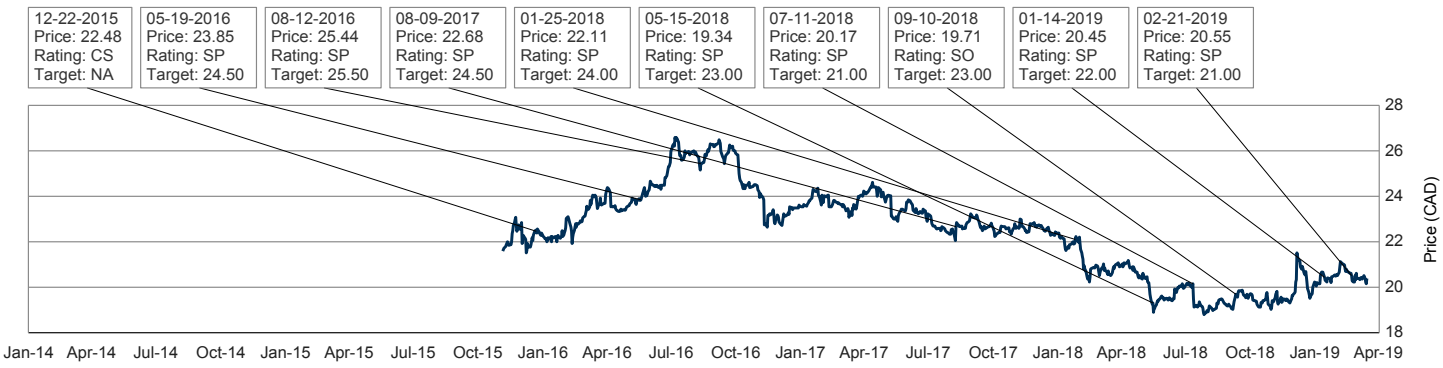


*Represents the value(s) that changed.
Ratings Legend: FS=Focus Stock; SO=Sector Outperform; SP=Sector Perform; SU=Sector Underperform; T=Tender; UR=Under Review; CS=Coverage Suspended; DC=Discontinued Coverage
Source: Scotiabank GBM estimates/Scotia Howard Weil estimates; FactSet.

Fortis Inc. (FTS-T) as of March 15, 2019 (in CAD)

*Represents the value(s) that changed.
Ratings Legend: FS=Focus Stock; SO=Sector Outperform; SP=Sector Perform; SU=Sector Underperform; T=Tender; UR=Under Review; CS=Coverage Suspended; DC=Discontinued Coverage
Source: Scotiabank GBM estimates/Scotia Howard Weil estimates; FactSet.

Hydro One Limited (H-T) as of March 15, 2019 (in CAD)



*Represents the value(s) that changed.
Ratings Legend: FS=Focus Stock; SO=Sector Outperform; SP=Sector Perform; SU=Sector Underperform; T=Tender; UR=Under Review; CS=Coverage Suspended; DC=Discontinued Coverage
Source: Scotiabank GBM estimates/Scotia Howard Weil estimates; FactSet.

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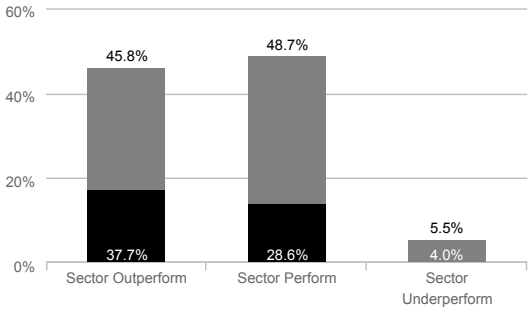

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MOODY'S
INVESTORS SERVICE

Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation

Introduction

We are seeking market feedback on a number of refinements that we are proposing to make in an update to our Regulated Electric and Gas Utilities Rating Methodology, which was last published in August 2009. The proposed updated rating methodology will continue to have a particular focus on regulatory risk and financial performance. The grid that is part of the proposed updated rating methodology is comprised of the same four factors as the existing grid: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength. However, it will provide additional granularity on individual factor scores, add new sub-factors, and increase the relative weighting of the financial metrics when determining the grid-indicated rating. We do not expect that implementation of the proposed refinements will lead to any changes in current ratings.

On a separate issue, we are also seeking market commentary on our evolving view of the credit supportiveness of the US utility regulatory framework. 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 utility 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. While US state regulatory environments have been characterized by a process that is more openly adversarial than some other global jurisdictions, there have been very few instances where eventual regulatory outcomes deviated enough from the established regulatory framework to severely undercut utility creditworthiness. In the few instances where inconsistent regulatory decisions have led to serious credit stress, courts have proved to be a reliable secondary support for utility credit worthiness through rulings that mandate that regulatory decisions must follow the established regulatory framework.

Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the US, with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.

Although the change of our US regulatory view does not by itself require the publication of a Request for Comment, based on an unusual confluence of factors in this instance, including the proximity in time of this change in view to an expected update in the methodology (even though the two are unrelated), the heavy weighting that regulatory factors have in our ratings as reflected in both the existing and proposed methodologies, the large number of US utilities that are potentially affected and the magnitude of debt outstanding in the sector, we think it is important to clearly communicate our developing views in this document and to solicit comments from market participants who may have interest.

We invite market participants to provide comments on this proposal and to make other suggestions for consideration by sending comments by October 23, 2013. Comments should be sent to RFC@moodys.com using the Request for Comment Form (the "RFC Response Form") available on the Request for Comment topic page on www.moodys.com. If your comments pertain to the proposed refinements to the rating methodology, please reference "Part I: Regulated Utility Methodology" in the topic line of your response. If your comments pertain to our evolving view of US utility regulation, please reference "Part II: US Utility Regulation" in the topic line of your response. The RFC response period for each of these topics will be open for at least 30 days from the date of publication of this Request for Comment.

Summary

PART I: Proposed Update of the Regulated Electric and Gas Utilities Methodology

Changes to the Grid: Additional sub-factors and changes to factor weighting

» We propose to add sub-factors under Factor 1- Regulatory Framework and Factor 2- Ability to Recover Costs and Earn Returns, to provide more granularity and to better distinguish among regulated utilities. The sub-factors include Sub-factor (1a) – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting) , Sub-factor (1b) – Consistency and Predictability of Regulation (12.5%), Sub-factor (2a) – Timeliness of Recovery of Operating and Capital Costs (12.5%), and Sub-factor (2b) - Sufficiency of Rates and Returns (12.5%). A preliminary draft of the grid for the updated rating methodology is included in Appendix A and shows the new sub-factors.

» We propose to refine Factor 3 – Diversification to focus more on regulatory diversity and the strength of the service territory economy as the key considerations in the scoring of the Market Position sub-factor. We also propose to change the Generation and Fuel Diversity sub-factor by replacing the emphasis on carbon fuels with the broader concepts of "challenged" and "threatened" sources of generation, as detailed in Appendix B.

» The range of possible scores under each factor, previously Aaa to B, has been expanded to include the Caa rating category. The purpose is to provide greater transparency in the thinking behind our ratings for issuers at the lower end of the spectrum.

» The Liquidity sub-factor, currently weighted at 10% in the grid, will be removed from the methodology grid entirely and instead analyzed as a key rating consideration outside the grid. However, there will be no diminution in our emphasis on liquidity as a key rating driver, since it always an important credit consideration and can become the primary rating consideration if it is mismanaged or becomes problematic for a utility.

» The weighting in the grid for the four financial ratios that comprise Factor 4 – Financial Strength will increase to 40% from 30%, although the specific ratios will remain the same. Additional weighting and importance will be given to the two cash flow to debt ratios: CFO pre-WC/Debt (to 15% from 7.5%) and CFO pre-WC less Dividends/Debt (to 10% from 7.5%), with the other two ratios continuing to be weighted at 7.5%. The above-mentioned expansion of the scoring range will cause some changes in grid parameters outlined for each rating category, primarily at the lower end of the grid.

» The scoring grids, including the ranges for financial ratios, are primarily oriented toward vertically integrated utilities. We are contemplating lowering the financial ratio threshold ranges by approximately one category for certain utilities viewed as having lower business risk, for instance many US natural gas local distribution companies (LDC's) and certain US electric transmission and distribution companies (T&D's, which lack generation but generally retain some procurement responsibilities for customers). The purpose would be to better align the grid-scoring to our view, reflected in current ratings, that utilities at the same rating category level with an inherent lower business risk can have somewhat lower financial metrics. Alternately, business risk may be addressed in a different manner; for instance, by incorporating it more broadly into the qualitative factor scoring grids. Typically, lower risk utilities would be those having no electric generation assets, very strong insulation from commodity risks, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters.

Additional summary comments about the updated rating methodology:

» As is our current practice, actual ratings of utility holding companies may be lowered by a notch or more because of structural subordination, and we are contemplating the potential of including this notching into our grid-indicated ratings to provide greater transparency. Our approach has and will consider the relative percentage of debt at the holding company versus debt at the operating subsidiaries, the diversity of holding company cash flows, the composition and materiality of non-utility businesses, and other considerations.

» We also propose to maintain our existing approach to notching between classes of debt. In most regions, we rate the senior secured debt of a utility one notch above its senior unsecured debt. However, US utility first mortgage bonds are typically rated two notches higher than the senior unsecured debt of the same issuer, given their first priority lien on critical infrastructure assets and the very high historical recovery rates for this class of debt in default situations.

The grid in the proposed methodology contains the same four factors as the existing rating methodology with the same weighting for each factor, but there are changes in the sub-factors and their weighting. We propose to assign equal weighting to four new sub-factors related to the regulatory framework and ability to recover costs and earn returns because we believe these sub-factors typically work together in approximately equal proportion as indicators of regulatory risk. These four sub-factors would still total 50% of the overall grid score, reflecting our view that the regulatory environment is the most important determinant of credit quality in the sector and generally comprises about half of the elements that are most pertinent for credit quality.

The grid in the proposed rating methodology would use the same four financial ratios but with some changes in weighting. The weighting of the two existing measures of cash flow generation relative to debt is to be increased because we believe these financial ratios are the strongest direct indicators of current capacity to service debt. The proposed 15% weight for CFO Pre-WC/Debt reflects our view that this is the single most predictive financial measure, followed in importance by CFO Pre-WC -

Dividends/Debt with a proposed 10% grid weighting. The additional weighting of these ratios is to be balanced by elimination of the separate liquidity sub-factor that has a 10% weighting in the existing grid. We propose to remove liquidity from the grid and consider it as a qualitative assessment outside the grid because its credit importance varies greatly over time and by issuer and accordingly is not well represented by a fixed grid weight. The weighting of the grid indicators for diversification are unchanged, but the proposed descriptive criteria have been refined to place greater emphasis on the economic and regulatory diversity of each utility's service area rather than the diversity of operations, because we think this emphasis better distinguishes credit risk.

As noted in the Summary above, we do not expect that implementation of the proposed refinements in the updated rating methodology will by themselves lead to any changes in current ratings.

PART II: Revised View of US Utility Regulation

» Our view of the credit supportiveness of regulatory jurisdictions around the globe is constantly evolving along with events. In most cases we would expect to simply update our view and to simultaneously make any rating changes that result. However, considering the large number of rated US utilities and the volume of their rated debt, combined with the magnitude of change in our view, we are soliciting comments on our rationale for a more favorable view of the US regulatory environment. 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 ratings may now be overly conservative.

» While we had previously viewed individual state regulatory risks for US utilities as generally 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. While state regulatory jurisdictions seem to be more prone to highly visible disputes and parochial political intervention than national regulatory frameworks, which has sometimes raised concerns about regulatory consistency, we now believe that the more openly adversarial process in the US does not lead to materially less reliable regulatory outcomes for credit quality.

» 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.

» 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 also balancing the needs of the state's commercial, industrial, and residential utility customers.

» There have been selected instances of regulatory and political pressure leading to financial distress for utilities in some US states, such as California, Illinois, and Maryland. However, it is noteworthy that state regulators have stopped short of triggering defaults after the experience in California where subsequent court rulings reversed regulatory actions that contributed to defaults by the two largest utilities in the state. We think regulatory decisions consider eventual judicial outcomes, and we propose to give more emphasis to the relatively consistent US judicial

framework as a factor that discourages highly inconsistent regulatory actions that would have a severe credit impact.

» Part of the evolution to our thinking is to give greater emphasis to the judicial framework into our analysis. A material number of litigated regulatory matters over the past decade could be viewed as an indication of a less supportive framework. However, the resultant body of case law has provided greater clarity into the rules of engagement for both utilities and regulators, which we view as providing a generally greater level of stability.

» We continue to believe US utilities may have more incentives to enter bankruptcy proceedings relative to similarly rated corporate issuers, due to their good track record of being able to reorganize and obtain rate relief while under the protection of federal bankruptcy courts. Nonetheless, utilities have experienced default rates that are lower than non-financial corporate issuers and much lower losses given default. This has been well documented in Moody's default and recovery studies on regulated utility debt.

» A comparison of key financial ratios used under the Regulated Electric and Gas Utilities Rating Methodology in rating utilities across several developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan) shows that US regulated utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers.

» We acknowledge that every regulatory framework will need to accommodate new realities and challenges that arise to confront the industry. Current examples of such challenges in the US include new nuclear construction, public policy initiatives on renewable energy, and the rise of distributed generation. However, our current view is that regulators and utilities will be able to reach reasonable agreements regarding these issues.

» As previously noted, our view of regulatory environments is constantly evolving and we normally make changes in our view and resulting rating changes without publishing a Request for Comment. We have seen a decline in the credit supportiveness of some regulatory environments that had been previously viewed as highly credit supportive. For example, we adopted a more conservative assessment for the regulatory environment and timely cost recovery for all of the Japanese utilities following the Fukushima disaster in 2011. This led to downgrades of their ratings and was reflected in lower scoring in our assessment of the regulatory and cost recovery factors in the grid.

For these reasons, we believe a more positive view of US utility regulation is warranted. This is expected to lead to a one notch upgrade of the ratings of most regulated utility credits in the US, with some exceptions. An improved view of US state regulatory frameworks is also likely to lead to higher scoring for many US utilities under the grid factors for utility regulatory frameworks and/or cost recovery provisions.

In most cases, we would expect all of the debt classes of a utility's capital structure to be upgraded by the same number of notches, although there could be some limited exceptions to this general rule. Most utility holding companies will be upgraded by the same number of notches to the extent that the upgraded regulated utility subsidiaries represent the holding company's predominant business and there are no extenuating circumstances, such as a large amount of holding company debt, substantial unregulated or other higher risk businesses, or other factors that may increase credit risk at the holding company.

While we anticipate that most US regulated utilities will be upgraded, there are issuer specific circumstances that may preclude an upgrade. These may include but are not limited to the following:

» Utilities that are part of corporate families that have significant unregulated or other higher risk operations as part of their overall business mix;

» Other corporate family considerations, such as a highly levered holding company, a complex corporate structure, or exposure to contagion risk due to the existence of lower rated affiliates;

» Utilities that are engaged in substantial construction programs for new generation plants (especially those with long lead-times or with technology that is less tested) or are in the midst of other major capital projects;

» Utilities that face material cost recovery risks or challenges related to significant capital investments;

» Utilities subject to concentration and/or event risk that are exposed to potentially sudden and unexpected changes in credit profile; and

» Utilities that are under downward credit pressure, particularly where this is reflected in a review for downgrade or a negative rating outlook.

Part I: Detailed Explanation of Proposed Refinements to Regulated Utilities Rating Methodology

This report includes a detailed rating grid that provides a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in this sector. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions, but actual importance may vary substantially. In addition, the illustrative mapping examples typically included in the rating methodology and some of our other published research use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company in most cases.

The rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to avoid greater complexity that would result in grid-indicated ratings that map more closely to actual ratings in favor of a simple and more transparent presentation.

Addition of Sub-factors under Factor 1 - Regulatory Framework and Factor 2 - Ability to Recover Costs and Earn Returns

We have added sub-factors under Factor 1 – Regulatory Framework and Factor 2 – Ability to Recover Costs and Earn Returns, to provide more granularity and to better distinguish among regulated utilities. With Factors 1 and 2 each weighted at a relatively high 25% of the overall grid outcome in the current methodology, incremental changes in a utility's regulation or cost recovery provisions are not easily indicated. Breaking down these two broad factors into two sub-factors will allow us to better reflect and communicate sometimes subtle differences in regulatory and/or cost recovery provisions among utilities. The new sub-factors include Sub-factor (1a) – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting) , Sub-factor (1b) – Consistency and Predictability of Regulation (12.5%), Sub-factor (2a) – Timeliness of Recovery of Operating and Capital Costs (12.5%), and Sub-factor (2b) - Sufficiency of Rates and Returns (12.5%). A draft of each of these new methodology sub-factors is included in Appendix A.

Factor 1 – Regulatory Framework

Sub-factor 1a – Legislative and Judicial Underpinnings to Regulatory Framework (12.5% weighting)

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is, as well as the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Finally, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it. The inclusion of this sub-factor also represents a more explicit acknowledgement that the judicial system can be a major determinant of the regulatory framework.

Sub-factor 1b – Consistency and Predictability of Regulation (12.5%)

For this sub-factor, we consider the track record of regulatory decisions, in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility. In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is encouraged by a relatively open regulatory process, and statements that are more clearly indicative of future actions and trends in decision-making.

Factor 2 – Ability to Recover Costs and Earn Returns

Sub-factor 2a – Timeliness of Recovery of Operating and Capital Costs (12.5%)

The criteria we consider in our assessments for this sub-factor include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a

formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to measure, or at least estimate, the lag between the time that a utility incurs major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

Sub-factor 2b - Sufficiency of Rates and Returns (12.5%)

The criteria we consider in our assessments for this sub-factor include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning its allowed returns. We examine rate case outcomes and compare them to the rate request submitted by the utility, to prior rate cases for the same utility and to recent rate case outcomes for a peer group of comparable utilities. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also the reasons given by the regulator, to determine the likelihood that such disallowances will be repeated in the future.

Refinement and Broadening of Factor 3 - Diversification

Sub-factor 3a – Market Position (5% or 10%)

The market position sub-factor will be refined to focus primarily on the economic diversity of the utility's service territory and the diversity of its regulatory regime. We will also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is typically a function of the size and breadth of the territory and the businesses that drive its GDP and employment. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. For vertically integrated utilities that have a meaningful amount of generation, this sub-factor will continue to have a weighting of 5%. For electric and transmission utilities without meaningful generation and for natural gas local distribution companies, this sub-factor will continue to have a weighting of 10%.

Sub-factor 3b – Generation and Fuel Diversity (0% or 5%)

We have changed this sub-factor by replacing the emphasis on exposure solely to carbon fuels in the current methodology with the broader concepts of exposure to "challenged" or "threatened" sources of generation. The sub-factor will continue to consider the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to economically shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to the aforementioned "challenged" or "threatened" sources. For issuers with a meaningful amount of generation, this factor will continue to have a weighting of 5% and for those with no generation, 0%. The definition of "challenged" and "threatened" sources of generation is included in Appendix B.

Liquidity Analyzed as Key Rating Consideration Outside of Methodology Grid

The Liquidity sub-factor, weighted at 10% in the current grid, will be removed from the grid and will be analyzed as a key rating consideration outside the grid. However, there will be no diminution in our emphasis on liquidity as a key rating driver. Liquidity is always an important credit consideration and can become the primary rating consideration if it is mismanaged or becomes problematic for a utility. Liquidity can be of particular importance in an industry in which companies frequently generate negative free cash flow due to high capital expenditures and significant dividend payments.

Our fundamental analysis of a utility's liquidity will remain unchanged in the updated rating methodology. Using our projections of the financial performance of an issuer, we evaluate how its projected sources of cash (cash from operations, cash on hand, and existing multi-year credit facilities) compare to its projected uses (including all planned capital expenditures, dividends, maturities of short and long-term debt, and our projection of potential liquidity calls on financial hedges). Our assessment of liquidity assumes no access to capital markets, no incremental credit facilities, no renewal of existing credit facilities, no decrease in capital expenditures from the plan, and no reduction in dividends.

Methodology Grid Expanded to Include "Caa" Category

The range of possible scores under each factor in the grid, currently ranging from Aaa to B, will be expanded to include a "Caa" category. The purpose of this change is to provide greater transparency in our scoring of the grid for ratings at the lower end of the spectrum. While regulated utilities predominantly comprise an investment grade sector, with most issuers unlikely to be assigned grid scores of Caa, regulated utilities experiencing severe financial stress and some utilities in certain emerging markets are more likely to be scored at the lower end of the grid. As is demonstrated in the revised methodology sub-factor grids included in Appendix A, the criteria for Caa scoring is categorized as utilities with very unsupportive regulatory frameworks, poor or highly uncertain cost recovery provisions, little to no diversification, and extremely weak financial metrics. The inclusion of the Caa level in the grid will provide greater granularity that better enables distinctions among utilities at the lower end of the grid.

Weighting of Four Key Financial Ratios Increased to 40% from 30%

The overall weighting of the four key financial ratios included in Factor 4 – Financial Strength will increase to 40% from 30%, although the ratios themselves will remain the same. The ratios will continue to include Moody's standard adjustments and, in certain instances, analyst-determined adjustments specific to the issuer.

In the revised grid that is part of the proposed updated methodology, additional weighting will be given to the two cash flow to debt ratios to better reflect their importance in our financial analysis and in our credit rating discussions. For the most part, the financial parameters outlined for each scoring category will remain the same, except at the lower end of the grid, where slight adjustments to the parameters have been made to accommodate the aforementioned expansion of the grid to include a "Caa" scoring category.

The four financial ratios and their revised weightings where applicable are listed below:

- Cash from operations before changes in working capital (CFO Pre-W/C) + interest / interest – 7.5%*
- CFO Pre-W/C / debt – 15% (up from 7.5%)*
- CFO Pre-W/C - dividends / debt – 10% (up from 7.5%)*
- Debt / capitalization or debt / regulated asset value (RAV) – 7.5%*

*It is anticipated that the illustrative examples in the updated rating methodology document will use three year historical averages for financial ratios. However, the factors in the grid can be assessed using various time periods and rating committees may find it analytically useful to examine both historic and expected future performance for various periods of time.

Financial Ratio Threshold Ranges May Be Lowered Based on Business Risk

In our view, the different types of utility entities covered under this methodology have different levels of business risk. Vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation. 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. Other types of utilities may have lower business risk, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters For instance, we tend to view many US natural gas local distribution companies (LDC's) and certain US electric transmission and distribution companies (T&D's, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers.

The scoring grids, including the financial ratio ranges in the Factor 4 grid shown in Appendix A, are primarily oriented toward vertically integrated utilities. We are contemplating lowering the financial ratio threshold ranges for utilities with lower business risk, including lower risk T&D's and LDC's in the US, by approximately one category. As an example, the threshold for a Baa category scoring in interest coverage for a vertically integrated utility (3.0x - 4.5x) would, for a utility with lower business risk, be the range for an A category scoring. The purpose would be to better align the grid-scoring to our view, reflected in current ratings, that at the same rating category, utilities with lower business risk can have somewhat lower financial metrics. Alternately, business risk may be addressed in a different manner, for instance by incorporating it more broadly into the qualitative factor scoring grids. In cases of T&D's that we do not view as having materially lower risk than their vertically integrated peers, for instance due to increased risks from substantial storm exposure, a regulatory framework that exposes T&D's to energy supply risk, large capital expenditures for required maintenance or upgrades, or increased regulatory scrutiny due to poor reliability or other issues, we may instead use the same Factor 4 grid ranges as those for integrated utilities. The same may be true for LDC's that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

Notching of Utility Holding Company Ratings Due to Structural Subordination May Be Included as a Grid Adjustment

Many utility company structures consist of a holding company that owns one or more operating subsidiaries. Under our current practices, ratings of utility holding companies are in many cases likely to be below those of operating companies due to structural subordination, since creditors of an operating subsidiary typically have a more direct claim on the cash flows and assets of these subsidiaries than do creditors of a holding company. When deciding whether or not to rate a holding company lower than it would be rated if it were an operating company, our considerations may include the relative percentage of debt at the holding company versus debt at the utility operating subsidiaries, operating company debt as a percentage of consolidated assets, the regulatory or effective limitations on movement of cash among the companies in the corporate family, the diversity of holding company cash flows, the composition and materiality of non-utility businesses, as well as other considerations. While structural subordination may exist in any industry sector, it is a particularly prevalent credit

issue in the utility sector, because incurrence of debt at both operating and holding companies is more widespread. We are contemplating the potential of including our notching practices into our grid-indicated ratings to provide greater visibility into the impact of this risk factor on ratings.

US Utility First Mortgage Bond Ratings are Typically Two Notches Above the Senior Unsecured Rating

In most regions, the typical rating relationship between different debt classes of regulated utilities is the same as for other investment grade non-financial corporate sectors, with senior secured debt rated one notch higher than the same issuer's senior unsecured rating. For the relatively small number of speculative grade utility issuers in certain regions, we apply our loss given default ratings methodology. However, our existing practice is to generally apply a two notch uplift to the first mortgage bond ratings of regulated electric and gas utilities in the US, and the updated rating methodology will not affect such rating relationships.

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

We may not always rate US first mortgage bonds two notches higher than the senior unsecured rating, for instance if the pledged property is not viewed by Moody's as being critical infrastructure, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

PART II: Additional Details on Our Evolving View of US Utility Regulation

Note that the following discussion of our evolving view of US utility regulation does not represent a change in our rating methodology and does not require that a Request for Comment be published. However, given the large number of US utilities affected and the magnitude of debt outstanding in the US utility sector, in the interest of clarity, we thought it was important to share our views broadly by including them in this document and soliciting comments from those who may have interest. This change in our view of US utility regulation is independent of proposed revisions to the rating methodology and would have the same rating impact under the existing rating methodology and the proposed update to the rating methodology.

The Overall US Regulatory Environment Has Become More Credit Supportive

In recent years we believe that some regulatory jurisdictions have become more credit supportive of regulated utilities, most notably in the US. While we had previously viewed the regulatory risk of US utilities, typically regulated at the state level, as being higher than utilities in most other developed countries where regulation occurs at the national level, we are contemplating a significant revision of our view. We see improved levels of regulatory support across the US, which includes the increased use of single issue riders and trackers, timely rate case outcomes or rate settlements, and a collaborative approach toward infrastructure investment and refurbishment.

The increased prevalence of riders, trackers, and other automatic cost recovery mechanisms in the US has materially reduced the amount of time between when a utility incurs and recovers costs, otherwise known as "regulatory lag." These changes have occurred incrementally – jurisdiction by jurisdiction or even issuer by issuer. We now believe that these changes, in aggregate, represent a significant improvement in cost recovery.

EXHIBIT 1
Average Regulatory Lag

Source: SNL Financial/Edison Electric Institute

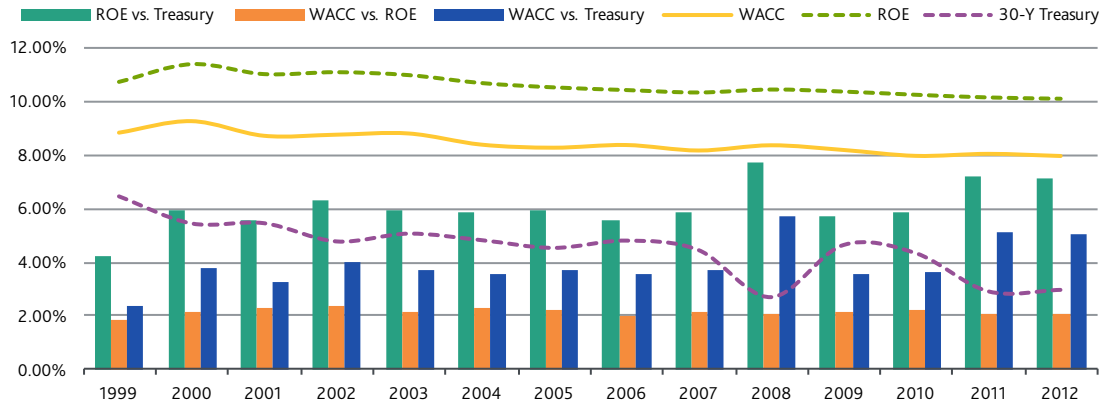
We also believe that the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states, while also balancing the needs of the state's commercial, industrial, and residential utility customers. We see a high degree of regulatory support continuing for much of the sector, as sustained low natural gas prices help to foster a collaborative relationship between utilities, regulators, and customers. Low fuel prices, which are the industry's most significant expense, provide increased economic flexibility for regulators to more easily approve and for utilities to implement base rate increases and other cost recovery mechanisms.

While state regulation has the potential to reflect more intensive disputes and parochial interests, a regional business model is particularly well suited to effective constituency outreach efforts. Utilities are important contributors to the well-being of their local communities, and are typically one of the largest publically traded companies and largest employers in their areas, as well as a major source of property taxes for state and local governments.

Although allowed ROE's are in decline, we observe that they remain at favorable levels compared to the historical average 30 year treasury rates and that ROE's are in line with historical levels of a utility's weighted average cost of capital. However, as treasury rates have begun to increase in 2013, we note that US utility ROE levels may not increase commensurately or on as timely a basis, potentially pressuring industry profitability going forward.

EXHIBIT 2

US Regulated Utility Returns vs. Costs



Source: SNL Financial/Bloomberg

Over the intermediate term, we see utilities experiencing a decline in general rate case filings, whether due to prescriptive and forward looking rate plans that have been approved by their regulators, or due to a utility's willingness to postpone rate cases and focus on managing costs in an environment of low inflation and low fuel costs. This has been an evolution from historical experience, where many utilities filed more frequent rate cases requesting smaller rate increases in order to reduce regulatory lag and avert potential customer resistance. We view this change as a result of several factors, including the aforementioned growing use of tracking mechanisms, as well as increased willingness of regulators to be more forward looking in their rate setting than historically. We have also found that differentiating among rate case outcomes among individual states has become increasingly difficult, as most utilities have in recent years experienced fair and balanced rate case outcomes, with many agreeing to rate settlements or other negotiated outcomes.

Part of the evolution of our thinking has been an increased emphasis on the relevant judicial framework in our assessment of a utility's regulatory framework. The material number of litigated regulatory matters in the US could be viewed as indication of a less supportive framework. However, it may simply reflect a greater tendency for parties to pursue court remedies, and the resultant body of relatively consistent case law has provided greater clarity into the rules of engagement for utilities and their regulators as well as greater visibility into the legal outcomes that would result from a regulatory dispute, thereby reducing the likelihood that a critical regulatory issue between a utility and regulatory commission would depart so far from expectations as to trigger a default.

We are contemplating a more favorable view of US regulatory environments, which would be reflected in stronger grid scoring for the regulatory framework and/or cost recovery factors for some US regulated utilities. We acknowledge that regulatory frameworks will need to accommodate new challenges and some may not support higher scoring under the methodology. Current examples of such challenges include utilities that are pursuing new nuclear construction projects in Georgia and South Carolina, public policy initiatives encouraging greater use of renewable energy, and the growth of distributed generation. These new market developments will continue to require collaborative solutions on the part of utilities, regulators, and political stakeholders. New rate compacts and incentive pricing mechanisms will need to be implemented that maintain both electricity network reliability and the financial health of the incumbent utility. Our current view is that regulators and utilities will be able to reach reasonable agreements regarding these issues.

While we have a more favorable view of US utility regulation in general, we acknowledge that challenging regulatory decisions will continue to occur in some jurisdictions as they have in the past, whether for political, populist, economic , or other reasons. The state of Florida, for example, had a long track record of credit supportive utility regulation before political intervention in utility rate cases in 2010 caused a deterioration in that regulatory framework. Following the election of a new governor and a the appointment of several new utility commissioners, Florida's regulatory framework has improved and is again considered credit supportive. Similarly, the state of California had a very good regulatory regime before the California energy crisis in 2000-2001 led to a dramatic decline in its credit supportiveness. Partly as a result of the lessons learned and improvements made following that experience, California's utility regulatory framework is again considered to be strong. Because US utility regulation remains highly fragmented and is primarily implemented at the state level, scenarios such as these will continue to emerge and influence future rating actions.

Sector Has Experienced Few Defaults, While Recovery Has Been Extraordinarily High

While there have been selected instances of regulatory and political pressure leading to financial distress for utilities in some US states (California, Illinois, and Maryland, for example), the overall number of US regulated utility defaults have been extremely low. This has occurred despite the propensity of regulated utilities to be more likely to consider and pursue strategic bankruptcy filings at an earlier stage of distress compared to unregulated non-financial corporate issuers. In the few instances where this has occurred, the company has continued to operate as a going concern, while regulators and other parties work collaboratively to resolve issues, allowing the utility to eventually exit bankruptcy proceedings.

The essential nature of the service that regulated utilities provide, as well as the critical nature of their generation, transmission, and distribution assets, makes it almost impossible to liquidate or otherwise disaggregate a utility during bankruptcy proceedings. As result, in the few regulated utility defaults that have occurred in the US, holders of secured debt eventually recovered 100% of principal and interest on a nominal basis in most cases. Recovery on other classes of debt has also been very high. This has been documented in Moody's default and recovery studies. Although not a key driver of our evolving overall view of US utility credit risk, these studies support and corroborate our view that ratings in the US regulated utility sector could be higher.

In 2009, we published a default study on the regulated utility industry entitled "Default, Recovery, and Credit Loss Rates for Regulated Utilities, 1983-2008". This study concluded that the history of regulated utility defaults indicates that Baa-rated regulated utilities have had significantly lower one-year default rates than Baa-rated nonfinancial corporate issuers, while A-rated utilities have had modestly higher one-year default rates than A-rated nonfinancial corporate issuers. Regulated utilities have also experienced lower loss given default rates (and, by definition, higher recovery rates) than other corporate issuers. Overall, this regulated utility default study showed that regulated utilities have experienced lower credit losses than non-financial, non-utility corporate issuers.

More recently, in December 2012 we published our first report on the historical credit performance of Moody's rated long-term infrastructure debts entitled "Infrastructure Default and Recovery Rates, 1983-2012H1." The study compared historical cumulative default and recovery rates for a broader set of infrastructure debts, including US regulated utilities, with non-financial corporate issuers. Like the previous regulated utility default study discussed above, the infrastructure default study also showed that A-rated corporate infrastructure debts have higher one year default rates but lower losses given default than non-financial corporate issuers, while Baa-rated corporate infrastructure debts (representing the higher proportion of corporate infrastructure debts) have very similar one year

default rates as Baa-rated non-financial corporate debts. However, as recoveries have been better among the infrastructure debts, total credit loss rates have been about 30% lower than those of non-financial corporate debts, although in absolute terms they are of the same order of magnitude, indicating overall comparability in performance.

Credit loss rates for Ba-rated corporate infrastructure debts (representing a small proportion of corporate infrastructure debts) are lower than for non-financial corporate debts. This is driven by regulated utilities' (the major sub-factor of all Ba-rated infrastructure corporate debts) very low propensity to default and their high recovery rates. All other Ba-rated corporate infrastructure debts have credit loss rates similar to their non-financial corporate counterparts.

US Utility Financial Metrics Are Higher Than Similarly Rated International Utility Peers

In comparing financial ratios we use in the rating methodology for Regulated Electric and Gas Utilities of approximately 150 utility companies in several developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan), US regulated utilities exhibit stronger ratios relative to similarly rated regulated international peers. For example, US utilities produce ratios of cash flow to debt that are almost twice as high as similarly rated international peers. The analysis included utilities with senior unsecured ratings in the A or Baa rating categories, and included electric, gas, networks, and water utilities, using historical financial data from Moody's Financial Metrics, as adjusted.

EXHIBIT 3

	Average (2005 - 2012)		Year-end 2012	
Jurisdiction	CFO / debt	FFO / debt	CFO / debt	FFO / debt
Average of international peers (A/Baa)	12%	12%	11%	10%
US - vertically integrated (A/Baa)	22%	23%	24%	23%
US - T&D, LDC (A/Baa)	18%	19%	19%	19%

Source: Moody's Financial Metrics

We note that federal tax policies, including accelerated bonus depreciation, have helped increase cash flows for many US utilities in recent years. But even if we exclude these benefits, in this example, by reducing the ratio of cash flow to debt by 300 basis points as a simplifying assumption, we still see more robust cash flow to debt ratios, roughly 50% higher than international peers.

EXHIBIT 4

	Average (2005 - 2012)		Year-end 2012	
Jurisdiction	CFO / debt	FFO / debt	CFO / debt	FFO / debt
Average of international peers (A/Baa)	12%	12%	11%	10%
US - vertically integrated (A/Baa)	19%	20%	21%	20%
US - T&D, LDC (A/Baa)	15%	16%	16%	16%

Source: Moody's Financial Metrics

In addition, US regulated utilities have lower balance sheet leverage and a larger equity cushion to absorb losses than similarly rated international peers, which is in part driven by the respective regulatory framework. With that said, higher leverage exhibited by some of the international peers is a function of those specific regulatory environments and the overall rate recovery structure in those

jurisdictions. US utilities also have a sizeable contribution towards their capitalization from generous federal tax policies through the use of deferred taxes.

EXHIBIT 5

	Average (2005 - 2012)			Year-end 2012		
Jurisdiction	Debt / Equity	Debt / Book Capitalization	Debt + Equity / Book Capitalization	Debt / Equity	Debt / Book Capitalization	Debt + Equity / Book Capitalization
Average of international peers (A/Baa)	223%	65%	94%	247%	66%	94%
US - vertically integrated (A/Baa)	116%	45%	84%	112%	43%	81%
US - T&D, LDC (A/Baa)	124%	45%	81%	125%	44%	78%

Source: Moody's Financial Metrics

Although we believe the wide differences in historical financial ratios is partly explained by the differences in regulatory framework, we are increasingly viewing the stronger US financials as more than mitigating the slightly higher overall regulatory risk profile that the US holds relative to its international peers that typically operate under a national regulatory regime.

In the table below, we show selected median financials for the 2005 – 2012 period against the year-end 2012 financials. The international peers saw a 23% increase in debt, a 29% increase in revenue, a 21% increase in assets and an 11% decline in CFO. In the US, we see an 18% increase in debt, a 2% decline in revenue, and a 20% and 28% increase in assets and CFO, respectively.

EXHIBIT 6

		2005 - 2012 Median Totals ($ Millions)				2012 total ($ Millions)			
Jurisdiction	Number of Companies	Debt	Revenue	Assets	CFO	Debt	Revenue	Assets	CFO
Total international utility peers	58	$309,566	$158,364	$513,109	$35,967	$374,061	$211,673	$628,912	$33,824
US - vertically integrated	57	$171,395	$166,941	$484,970	$35,271	$202,311	$171,198	$600,779	$48,044
US - T&D, LDC	38	$78,719	$79,523	$213,408	$14,229	$86,494	$67,511	$238,117	$16,712
Total US regulated utility	95	$250,114	$246,463	$698,378	$49,500	$288,805	$238,709	$838,896	$64,756
Total regulated utilities	153	$559,680	$404,828	$1,211,487	$85,467	$662,866	$450,383	$1,467,808	$98,580

Source: Moody's Financial Metrics

Credit Supportiveness of Some Regulatory Jurisdictions has Declined in Recent Years

In recent years we have perceived a decline in the credit supportiveness of some regulatory jurisdictions that we had previously viewed as highly credit supportive. For example, following the 2011 Fukushima nuclear disaster in Japan, we downgraded the ratings of nine Japanese utilities, partly reflecting our expectation of a less supportive Japanese government regulatory framework for these utilities going forward. At the same time, we re-evaluated the Japanese utility industry's relative position as a regulatory environment and modified the grid scoring for Japanese utilities accordingly.

While we continue to view the Japanese regulatory framework as credit supportive due to the strong support of the utilities by their key regulator, the Ministry of Economy, Trade, and Industry (METI), as well as the Japanese government, we felt it had become somewhat less supportive than before the

Fukushima crisis, particularly as it relates to nuclear power. As a result, we lowered the grid scoring for Factor 1 of the methodology, Regulatory Framework, to either Aa or A from Aaa, depending on each utility's particular circumstances. Based on our current view, Japan's electric utilities that have nuclear generation capabilities are currently scored A for this factor, due to the ongoing uncertainty associated with regard to nuclear generation, while in general the gas utilities and non-nuclear exposed electric utilities are currently still viewed as appropriately scored at the Aa level.

Our updated view was also reflected in the grid scoring for Factor 2 – Ability to Recover Costs and Earn Returns for Japan's utilities. Although Japanese utility regulation includes statutory provisions that insure the timely recovery of operating, capital, fuel and financing costs, plus a rate of return, there are some limitations on automatic fuel related rate increases for both electric and gas utilities. This limitation, in addition to some of the utilities expanding internationally and into non-utility businesses, resulted in our decision to slightly revise the grid scoring for this factor, with most of the utilities initially lowered to an A score from a Aa score.

Subsequently, the prolonged shut-down of nuclear plants in Japan and the resulting higher reliance on fossil fuels have significantly raised operating costs for those utilities previously reliant on nuclear power. Although some of the nuclear-dependent utilities have successfully raised their tariffs, the new rates are insufficient to return them to profitability, as they are based on cost structures that incorporate some nuclear restarts. As a result, the scoring of some of the nuclear dependent utilities for this grid factor was subsequently lowered to Baa.

Conclusion

The refinements we are proposing to make to our Regulated Electric and Gas Utilities Rating Methodology are intended to provide additional granularity on individual factor grid scores by adding new sub-factors and to increase the relative weighting of the financial metrics when determining the grid-indicated rating. The methodology will continue to emphasize both regulatory risk and financial performance. The grid that is part of the methodology will continue to focus on the same four factors: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength. The proposed refinements are not expected to lead to any rating changes. Comments on these refinements are welcome using the instructions on the cover page of this document.

At the same time, and unrelated to the update of the rating methodology, we are seeking comment on our view that the relative credit supportiveness of the US utility regulatory framework has improved, and that we should assess regulatory risks more favorably for US utilities. Improvements include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, generally fair and open relationships between utilities and regulators, and the demonstration of a strong judicial framework. As a result, we intend to take a more positive view of US utilities in factoring regulatory risks into ratings. This would also be reflected in higher grid scoring for utility regulatory frameworks and cost recovery provisions under the rating methodology. Our more favorable view of US regulation relative to other global jurisdictions is expected to lead to a one notch upgrade of most US regulated utilities, with some exceptions. In most cases, we would expect all of the debt classes of a utility's capital structure to be upgraded by the same number of notches, although there could be limited exceptions. The US utility sector's low number of defaults, high recovery levels, and comparatively strong financial metrics provide additional corroboration for our view that ratings should generally be higher. Comments on our evolving view of US utility regulation are also welcome using the instructions on the cover page of this document.

Appendix A: Preliminary Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings to Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a matter that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. . There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may be credit supportive, but often unenforceable. The regulator's authority may have be seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of unwillingness of regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy , but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourages investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	"Challenged Sources" are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	"Threatened Sources" are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

	Sub-Factor Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
(CFO pre-WC + Interest) / Interest	7.5%	≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
(CFO pre-WC) / Debt	15%	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
(CFO pre-WC – Dividends) / Debt	10%	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
Debt / Capitalization *	7.5%	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / RAV *		< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 85%	85% - 95%	≥ 95%

* The use of Debt / Capitalization or Debt / Regulated Asset Value (RAV) will depend largely on the regulatory regime in which the utility operates. Debt / Capitalization is currently used for most of the issuers rated under this methodology, because in many regions (currently including North America and many Asian countries) RAV does not exist. Where RAV exists, the Debt / RAV ratio may be preferable. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services, and the RAV represents the value (determined by regulators) on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules, we view Debt / RAV as the better credit measure and use it for this sub-factor. Where RAV does not exist or the method of calculation is subject to arbitrary or unpredictable revisions, we use Debt / Capitalization.

Appendix B: "Challenged" and "Threatened" Generation Sources

By "Challenged Sources", we mean generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe that plant closure is likely.

By "Threatened Sources", we mean generation plants that are not currently able or permitted to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US for which retro-fitting to meet mercury and air toxics standards is not economically viable or cannot be achieved by the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

Moody's Related Research

Rating Methodology:

» Regulated Electric and Gas Utilities, August 2009 (118481)

Cross-Sector Rating Methodologies:

» Loss Given Default for Speculative-Grade Non-Financial Companies in the US, Canada, and EMEA, June 2009 (114838)

» Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers, February 2007 (102248)

Special Comments:

» Default, Recovery, and Credit Loss Rates for Regulated Utilities, 1983-2008, May 2009 (115424)

» Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)

» Cost Recovery Provisions Key to U.S. Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)

» Liquidity: A Key Component to Investor-Owned Utility Ratings and Credit Quality Evaluating a Utility's Liquidity Profile, September 2010 (127546)

» Re-Evaluating Japanese Utility Credit Quality post-Fukushima, July 2011 (133194)

» Pacific Northwest Utilities: Regulatory Support Paves Way for Improving Credit Profiles, November 2011 (146170)

» Infrastructure Default and Recovery Rates, 1983-2012H1 December 2012 (146791)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

» contacts continued from page 1

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JUNE 23, 2017

INFRASTRUCTURE

MOODY'S INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

SUMMARY 1
ABOUT THE RATED UNIVERSE 3
ABOUT THIS RATING METHODOLOGY 4
DISCUSSION OF THE GRID FACTORS 6
APPENDIX A: REGULATED ELECTRIC AND GAS UTILITIES METHODOLOGY FACTOR GRID 29
APPENDIX B: APPROACH TO RATINGS WITHIN A UTILITY FAMILY 35
APPENDIX C: BRIEF DESCRIPTIONS OF THE TYPES OF COMPANIES RATED UNDER THIS METHODOLOGY 38
APPENDIX D: KEY INDUSTRY ISSUES OVER THE INTERMEDIATE TERM 40
APPENDIX E: REGIONAL AND OTHER CONSIDERATIONS 44
APPENDIX F: TREATMENT OF POWER PURCHASE AGREEMENTS ("PPAS") 46
METHODS FOR ESTIMATING A LIABILITY AMOUNT FOR PPAS 48
MOODY'S RELATED RESEARCH 49

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON AUGUST 2, 2018. WE HAVE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY.

THIS RATING METHODOLOGY WAS UPDATED ON FEBRUARY 15, 2018. WE HAVE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe
» A summary of the rating methodology
» A discussion of the key rating factors that drive ratings
» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

[2] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[3] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[4] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

[5] A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest / Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

[6] For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

[7] Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$

[8] In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Filed: 2021-04-19, EB-2020-0290
Exhibit L-C1-01-Staff-040, Attachment 3, Page 12 of 51

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that

has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation 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.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

[10] In certain circumstances, analysts may also apply specific adjustments.

[11] We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-

streamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- Substantial diversity in cash flows from a variety of utility OpCos
- Meaningful dividends to HoldCo from unlevered utility OpCos
- Dependable, meaningful dividends to HoldCo from non-utility OpCos
- The group's investment program is primarily in strong utility businesses
- Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity

generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of

these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

[15] See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

- Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo
- Differentiation of the regulatory frameworks of the various OpCos
- Specific ring-fencing provisions at particular OpCos
- Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets
- Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family
- The extent to which higher leverage at one entity increases default risk for other members of the family
- An entity's exposure to or insulation from an affiliate with high business risk
- Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.
- The relative size and financial significance of any particular OpCo to the HoldCo and the family

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of

electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its

power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
[18] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the

utility. In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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Research Update:

SNC-Lavalin Group Inc. 'BB+' Ratings Affirmed; Outlook Remains Negative On Slower-Than-Expected Deleveraging

May 15, 2020

Rating Action Overview

- SNC-Lavalin Group Inc.'s (SNC) credit profile in the past three quarters has been improving in line with what we expected last August and the probability of a downgrade had been receding.
- However, we believe the emergence of the COVID-19 pandemic will lead to weaker-than-expected earnings and cash flow this year for SNC due to a weaker economic environment and lower construction activity.
- In our view, there remains heightened uncertainty regarding the material improvement in the company's credit measures that we expect in 2021, including adjusted debt-to-EBITDA below 3x.
- As a result, on May 15, 2020, S&P Global Ratings affirmed its ratings on SNC, including its 'BB+' issuer credit rating on the company; however, the outlook on the company remains negative.
- The negative outlook primarily reflects uncertainty in the company's ability to improve earnings and cash flow to an extent that leads to adjusted debt-to-EBITDA below 3x by next year.

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Rating Action Rationale

A weaker economic environment should result in lower earnings and cash flow over the next couple of years than we previously anticipated. SNC's performance in the past three quarters was trending about in line with our previous expectations and the probability of a downgrade was receding. However, the emergence of the COVID-19 pandemic meaningfully disrupted construction activity in the regions in which SNC operates. As a result, higher costs and weaker demand for services this year are expected to result in weaker earnings and cash flow generation than we had previously anticipated. We now expect 2020 adjusted EBITDA to be about 25% lower than our estimates in our last research update on SNC, published in August 2019. Our forecast credit metrics this year include adjusted debt-to-EBITDA in the mid-3x area with negative free operating cash flow (FOCF) generation, which remains weak for the rating and supports our

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EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 2 of 8

negative outlook on the company.

Our estimated credit measures and cash flow expectations in 2020 are about consistent with our previous downside scenario. In addition, there is a high degree of uncertainty regarding the impact that the pandemic could have on SNC's business. Moreover, while the risk appears to be abating, the company remains exposed to additional losses on its lump-sum turnkey projects. In our view, the potential for earnings and cash flow below our expectations this year could lead to credit measures we do not view as commensurate with the ratings. Furthermore, weaker-than-expected market conditions and operating results could lead to a materially higher free cash flow deficit. We believe this could limit SNC's ability to generate adjusted debt-to-EBITDA below 3x next year, which we require to stabilize the outlook on the rating.

The affirmation of our 'BB+' issuer credit rating on SNC reflects our view that the company's performance over the past three quarters was trending in line with what we previously expected and that demand should recover next year, contributing to positive FOCF generation and leverage falling to the mid-2x area in 2021.

Furthermore, we believe SNC's financial policies will continue to support leverage below 3x in the long term. We believe this deleveraging will stem from relatively stable earnings within SNCL Engineering Services, which we expect will contribute at least C$600 million of annual EBITDA (excluding capital investments and corporate costs) beyond 2020. Our base-case scenario also assumes that there will be no significant cost overruns on the remaining lump-sum turnkey (LSTK) contracts and that losses at SNCL Projects will be contained below C$150 million over the next 12 months.

Outlook

The negative outlook primarily reflects uncertainty in the company's ability to recover earnings and cash flow so that adjusted debt-to-EBITDA returns below 3x by next year. We base this on risks related to potential cost overruns on remaining LSTK projects in SNC's backlog if poorly executed. It also incorporates the risk of weaker demand for engineering services amid disruptions stemming from the coronavirus pandemic.

Downside scenario

We could lower the ratings on SNC within the next 12 months if we expect adjusted debt-to-EBITDA to remain above 3x in 2021. This could occur from cost overruns on remaining LSTK projects, or if the effects of the pandemic on the company's financial results this year are meaningfully worse than we expect. We could also lower the ratings if we expect SNC's longer-term growth prospects or profitability within engineering services will be weaker than those of its peers, potentially contributing to our view that SNC's competitive position has deteriorated.

Upside scenario

We could revise our outlook on SNC to stable within the next 12 months if the company's operating performance is generally in line with our expectations, potentially leading us to believe that execution risk on SNC's LSTK project backlog has abated and that the other areas of the business should continue to support our assessment of SNC's competitive position. In this scenario, we would have more conviction that adjusted debt-to-EBITDA will be below 3x beyond 2020 with

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Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 3 of 8

positive FOCF generation.

Company Description

SNC is Canada's largest engineering firm, providing engineering, construction, and operations-maintenance services through its network of offices around the world; the company generated about C$9.5 billion of revenue in 2019. SNC provides services in a variety of sectors including oil and gas, mining and metallurgy, and infrastructure and power. It also invests in infrastructure concessions (capital investments), the largest being its equity interest in 407 ETR, which operates and tolls a highway in southern Ontario.

Our Base-Case Scenario

Assumptions

- GDP in Canada to decline 5.3% in 2020 and increase 6.0% in 2021; GDP in U.S. to decline of 5.2% in 2020 and increase 6.2% in 2021; GDP in the U.K. to decline 6.5% in 2020 and increase 6.0% in 2021
- Revenue within SNC's Engineering, Design, Procurement, and Management (EDPM) business to change about in line with GDP while demand for nuclear and infrastructure services is relatively stable
- SNC no longer bids for new LSTK projects and that 50%-60% of the remaining backlog will be completed by the end of 2021
- Corporate and other operating costs (including restructuring and integration) of C$100 million–C$120 million per year
- Adjusted EBITDA margin of about 6% in 2020 with further improvement to 8%-9% in 2021
- The improvement in margins beyond 2020 reflects our view that the significant losses in 2019 within SNCL Projects should roll off, a more profitable mix of business as the company focuses on reimbursable work, and lower restructuring and integration costs. This should more than offset earnings pressure from COVID-19-related weaker demand and operating disruptions during 2020
- SNC refinances upcoming debt maturities
- No share buybacks or acquisitions through 2020
- SNC retains its 6.76% stake in Highway 407 ETR, from which we assume it receives C$40 million-C$60 million of annual dividends

Key metrics

	2019A	2020E	2021E
Adj. revenue (mil. C$)	9,253	8,000-8,500	7,500-8,000
Adj. EBITDA (mil. C$)	313	480-520	680-720
Adj. EBITDA margin (%)	3.4	About 6.0	8-10

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Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 4 of 8

	2019A	2020E	2021E
Adj. debt-to-EBITDA (x)	4.3	Mid-3x	Mid-2x
Adj. FFO-to-debt (%)	7.7	18-22	35-40
Adj. FOCF-to-debt (%)	(3.8)	(5)-(10)	20-30

A--Actual. E--Estimate. FFO--Funds from operations. FOCF--Free operating cash flow.

Liquidity

Our liquidity assessment reflects our view that SNC's sources of liquidity should be able to cover the company's uses of cash within the next 24 months by more than 2.0x and that the ratio should remain above 1.0x in a stress scenario, whereby EBITDA is 30% lower than our forecast (see sources and uses). Our assessment also incorporates our view that SNC is likely able to absorb a high-impact, low-probability event with limited need for refinancing given that it does not have any meaningful maturities over the next couple of years. We also believe SNC has sound banking relationships. That said, we consider a stronger liquidity assessment inappropriate at this time, in part due to our view that SNC lacks high standing in credit markets following significant underperformance in recent years.

Principal liquidity sources include:

- About C$2.1 billion cash and cash equivalents at March 31, 2020
- About C$1 billion available under the company's revolving credit facility that matures May 15, 2022
- Annual funds from operations of C$400 million-C$500 million

Principal liquidity uses include:

- Intrayear working capital requirements that could reach as high as C$600 million, but should decline over time as SNC's backlog of LSTK projects winds down
- Annual capital expenditure (excluding capital investments) of C$60 million–C$80 million in 2020 and C$90 million-C$110 million in 2021
- Annual dividend payments of about C$15 million
- C$300 million debt maturity in November 2020 and C$175 million in March 2021
- Annual lease payments (excluding interest portion) of about C$130 million

Covenants

SNC must comply with certain financial covenants under its revolving credit facilities. These include a maximum net recourse debt-to-EBITDA of 3.75x.

We believe there is sufficient headroom for forecast EBITDA to fall by 30% or debt to increase by 25% without the company breaching any covenant limits.

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Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 5 of 8

Other Credit Considerations

On Aug. 15, 2019, SNC completed a partial sale of its Highway 407 ETR investment (about 60% of its holdings) to Canada Pension Plan Investment Board. Net proceeds received from the sale of approximately C$3 billion were used to reduce debt and strengthen SNC's liquidity position.

SNC still has a 6.76% stake in Highway 407 ETR, with an implied value of approximately C$2 billion based on the sale completed last year. Therefore, we still ascribe strong credit enhancement to the rating based on the company's remaining equity investment. We do not fully capture this investment in our business or financial risk profiles for SNC, based on our view that it is a nonstrategic financial investment.

Our base-case forecast assumes SNC does not sell its remaining stake in Highway 407 ETR, but we understand it could at some point. We believe that credit measures could further improve if the company fully divested its stake, with adjusted debt-to-EBITDA declining and potentially being sustained below 1.5x. In our view, SNC's financial policy is to maintain low financial risk, which we consider an important characteristic for the company to win contracts at favorable terms.

Issue Ratings - Recovery Analysis

Key analytical factors

- Our '3' recovery rating and 'BB+' issue-level rating on SNC's senior unsecured notes indicate our expectation for meaningful (50%-70%; rounded estimate: 50%) recovery in the event of default.
- Our simulated default scenario contemplates a default in 2024, stemming from significant losses and free cash flow deficits that limit SNC's ability to fund its fixed charges and exhausts available liquidity. This could occur from very poor execution on the company's remaining LSTK contracts along with meaningful deterioration in the competitive position of its remaining businesses.
- Our recovery analysis assumes a reorganization value for the company of about C$1.6 billion, reflecting emergence EBITDA of about C$319 million and a 5x multiple.
- We assume that, in a hypothetical bankruptcy scenario, the company's C$2 billion revolving credit facility is 85% drawn.
- Our recovery analysis assumes no value from capital investments will remain available to SNC's unsecured creditors. This reflects our assumption that SNC will sell all or most of its capital investments on the path to default and that if any value remains at default, it will not exceed the amount of claims that have priority over those assets.
- As a result, we also exclude SNC's limited and non-recourse debt from our recovery analysis.

Simulated default assumptions

- Simulated year of default: 2025
- Multiple: 5.0x
- EBITDA at emergence: C$319 million

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EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 6 of 8

- Gross recovery value: C$1.6 billion
- Net recovery value after administrative expenses (5%): C$1.5 billion
- Obligor/non-obligor valuation split: 100%/0%

Simplified waterfall

- Estimated value for unsecured claims: C$1.5 billion
- Estimated unsecured claim: C$3 billion
- --Recovery range: 50%-70% (rounded estimate: 50%)

All debt amounts include six months of prepetition interest.

Ratings Score Snapshot

Issuer Credit Rating: BB+/Negative/--

Business risk: Fair

- Country risk: Low
- Industry risk: Moderately high
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Positive (+1 notches)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Fair (no impact)
- Comparable rating analysis: Neutral (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global

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Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4
Page 7 of 8

Corporate Issuers, Dec. 16, 2014

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Related Research

- European Economic Snapshots: Larger Risks To Growth Loom Ahead, May 5, 2020
- COVID-19 Causes More Severe Disruption For Canada's Economy, April 17, 2020
- An Already Historic U.S. Downturn Now Looks Even Worse, April 16, 2020
- SNC-Lavalin Group Inc. Ratings Unaffected By Settlement Of Federal Charges, Dec. 19, 2019
- SNC-Lavalin Group Inc. Downgraded To 'BB+' From 'BBB-' On Weakened Financial Risk Profile, Aug. 19, 2019

Ratings List

Ratings Affirmed; Recovery Rating Unchanged

SNC-Lavalin Group Inc.	
Issuer Credit Rating	BB+/Negative/--
Senior Unsecured	BB+
Recovery Rating	3(50%)

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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EB-2020-0290
Exhibit L
C1-01-Staff-040
Attachment 4

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The following are recent external events that were deemed relevant to OPG.

External Event	Description
Recent flooding events in Alberta and Michigan	On April 26, 2020 an ice jam, roughly 25 kilometres in length, that had formed on the Athabasca River near Fort McMurray effectively dammed the river and forced water levels to rise by 4.5 to 6 metres across low-lying areas through the region. Initial damage estimates indicated that over 1,200 structures were affected by the flooding with approximately 13,000 people evacuated from the area. According to the Insurance Bureau of Canada, the flood caused over $228 million in insured damage. In addition, the Alberta Government announced $147 million of support through the Disaster Recovery Program. On May 19, 2020 heavy rains contributed to a breach at the Edenville Dam in Michigan unleashing a torrent of water downstream that caused the Sanford Dam to overtop and fail. The resulting flooding forced approximately 10,000 people to evacuate their homes. Damage to approximately 2,500 homes and businesses has been estimated at greater than US$175 million. Lawsuits are being filed against the dam owner - Boyce Hydro LLC (Boyce Hydro), seeking property damages and response and recovery expenses. FERC had previously revoked Boyce Hydro's license to generate hydroelectric power at the Edenville Dam in September 2018 after years of failed attempts to have Boyce Hydro address safety concerns. **Relevance to OPG:** Flooding associated with ice jams present unique hazards when compared with natural floods, as water levels rise more rapidly along sections of the river channel and they are more difficult to predict. The Athabasca River in Alberta is unregulated flow (i.e. no dams), which significantly restricts the ability to manage water levels. OPG actively works to establish stable ice covers and managing flows on other rivers. When ice jams do occur, river operations can work effectively at releasing them before hazardous conditions can form. With regard to the dam failures in Michigan, an independent forensic team has been established to report to the State and the FERC. OPG's dam safety staff are reviewing the event for lessons learned. OPG has also submitted a briefing on potential impacts at the request of our Marsh Canada Insurance.
Pacific Gas & Electric pleads guilty to 84 counts of involuntary manslaughter in California wildfire	On June 16, 2020, California utility company Pacific Gas & Electric (PG&E) pleaded guilty to 84 counts of involuntary manslaughter stemming from a 2018 wildfire in Northern California. The wildfire started as a result of the utility company's transmission lines. The guilty plea, part of an agreement with prosecutors, will have PG&E pay a US$3.5 million fine. The plea deal will also allow PG&E to exit bankruptcy pending a judge's approval. As part of the plan to exit bankruptcy, PG&E will also pay US$13.5 billion in damages for people who had lost homes and businesses as a result of the wildfire. PG&E will remain an investor-owned utility, however the California governor is requiring an overhaul of the company's board, a new leadership structure and an agreement that the state could take over the utility if it did not fulfill its obligations under the bankruptcy plan. About half of the US$13.5 billion in compensation PG&E is paying wildfire victims will be in the form of company stock, leaving roughly 70,000 of them owning a little more than 22 percent of PG&E once it leaves bankruptcy. Last year, the governor signed a bill to create a US$20 billion fund that will help cover the costs of future fires. The fund is financed with money from PG&E and two other large utilities and from ratepayers.

External Event	Description
	Relevance to OPG: ECRE owns a small facility in California with a second acquisition closing in September. ECRE only has generation assets in California and no transmission which limits the potential exposure experienced by PG&E. Currently, there is no Board approved strategy for further expansion in California.
Europe needs all energy sources for recovery and to meet its long-term climate goals	The International Energy Agency (IEA) released a comprehensive review of the entire energy system in Europe as the European Commission of Energy attempts to deliver the European Green Deal. The Green Deal was launched in December by the commission in a bid to make the bloc climate neutral by 2050. The IEA's view is that all zero carbon technologies are required; the exclusion of nuclear energy would make reaching Europe's climate targets more challenging. European nuclear plants currently provide most of the continent's low-carbon electricity but half of the nuclear generation capacity is expected to be retired in the next 5 years unless operating periods are extended. Investing in existing nuclear power plants, new nuclear build and supporting innovation in small modular reactors are among the measures set out to support a broad range of clean energy technologies in an energy-focused COVID-19 economic recovery plan by the IEA. The IEA report confirms that extending the operating life of existing nuclear plants will support thousands of jobs, reduce fossil fuel imports, improve electricity security by adding to power system flexibility, and improve the affordability of electricity to consumers. **Relevance to OPG:** Nuclear power is not always seen as a "clean" energy source in terms of fighting climate change due to out-dated anti-nuclear sentiment. Many green-energy funds and investors continue to be unwilling to incorporate nuclear investment. This can both decrease the availability of capital and increase its cost, inappropriately resulting in nuclear being excluded as a viable clean source of energy and causing continuing higher carbon emissions that could be reduced. OPG is working with government and industry stakeholders to promote the benefits of nuclear energy and drive policy change.

External Event	Description
2020 is expected to be the warmest year on record globally	A persistent heat wave resulted in record hot summer weather in Canada, the United States, Europe and the Middle East in late June and early July. This prolonged and intense heat event was the hottest stretch of weather in more than a decade. Ottawa typically has five days a year with temperatures above 32°C. As of July 22, 2020, there have been 11 days this year. The models for 2020 suggest that Ontario should expect an extremely hot and dry summer. Longer term models project greater extremes and year-to-year variability in temperature. **Relevance to OPG** *Health and Safety* Working in hot environment when combined with physical activity may lead to heat-related illness. OPG Health and Safety proactively launched the 2020 Nuclear Heat Stress Campaign to prevent the onset of heat related illnesses across the Nuclear Fleet. This campaign includes: • Employee education and increasing their awareness on heat stress via timely execution of heat stress communication plan; • Conducting iCare Snapshot observations to ensure the affected work group(s) have the support and resources to manage heat stress; • Monitoring trends of proactive and reactive Station Condition Reports related to heat stress and ensure immediate intervention to prevent escalation of any heat stress related issues; and • Implementing site specific heat stress controls. *Operations* During heat waves, high temperatures also affect thermal efficiency and generating capacity of gas and nuclear powered plants. There may also be impacts on systems cooled with lake water and the demand on AC units in equipment rooms with temperature sensitive instrumentation and controls. Risks associated with algae and zebra mussels are also exacerbated by increased and prolonged heatwaves. During Q3, ERM will be following up with the BUs on the implications of heat waves on both risks from an employee safety perspective as well as an asset integrity/performance perspective.

McKinsey & Company

Electric Power & Natural Gas Practice

Why, and how, utilities should start to manage climate-change risk

Extreme weather events are exacting a high—and rising—price. Utilities need to devise and implement strategies to adapt.

by Sarah Brody, Matt Rogers, and Giulia Siccardo

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April 2019

The Fourth National Climate Assessment, released in late 2018, stated that climate change was already having noticeable effects in the United States and predicted "more frequent and intense extreme weather and climate-related events," such as floods and hurricanes. For utilities, the assessment concluded, the possibilities were grave: lower efficiency, higher expenses, and more power outages—even as demand for energy rises. And many utilities are not ready. As the assessment noted, "Infrastructure currently designed for historical climate conditions is more vulnerable to future weather extremes and climate change."

The cost of extreme weather is already high, and the frequency and the cost to life and property of extreme weather events has increased in recent years. If such events become more common or intense, as the assessment predicts, the price will be even higher. Even now, some utilities are making investments in long lived assets in risky locations, increasing system vulnerability and balance sheet risk. On that basis, we believe there is a strong case for utilities to start now to take steps on climate-change adaptation. And there are ways for them to do so—for example by strengthening the grid, exploring investments in batteries and microgrids, and working with new partners.

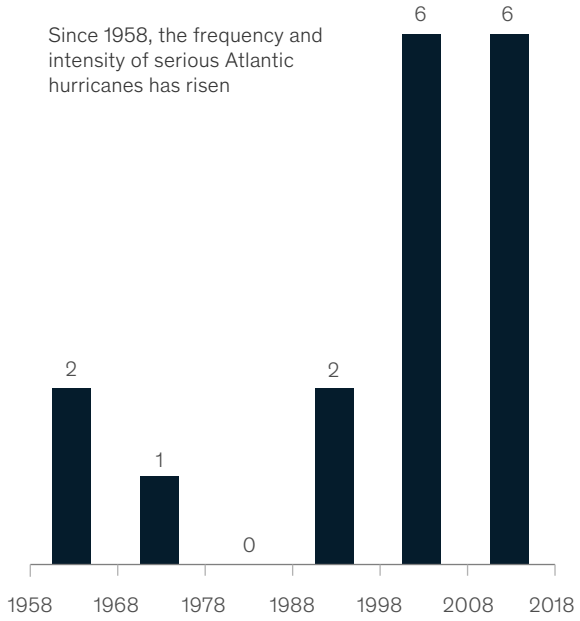
The brewing cost storm for utilities

In 2017, Hurricane Irma made landfall in the Caribbean and Florida. A category 4 and 5 storm, Irma damaged 90 percent of the buildings on the island of Barbuda and caused the fourth-largest blackout in US history. The total cost of damage was $50 billion. And Irma was no outlier. Since 1958, the frequency and intensity of serious Atlantic hurricanes, like Irma, has risen (Exhibit 1).

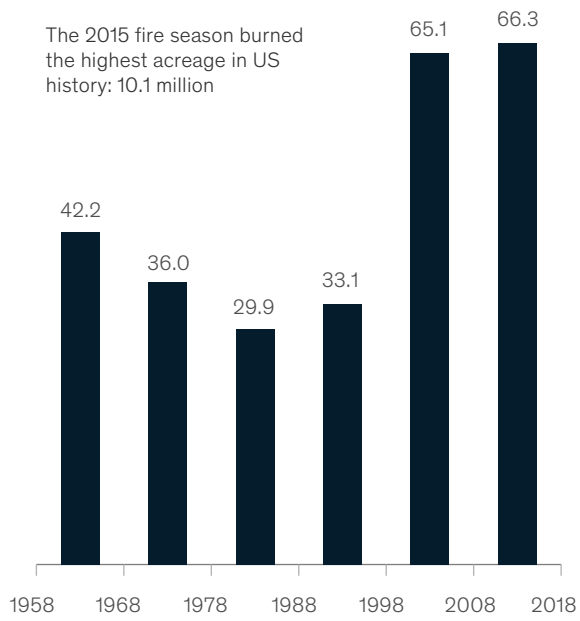
Exhibit 1

Hurricanes and wildfires are getting worse.

Above-average-strength Atlantic hurricane seasons,[1] number per decade



Area burned by wildfires in the US, millions of acres per decade



[1] The National Oceanic Atmospheric Administration uses a metric called ACE, or accumulated cyclone energy, which accounts for the strength, frequency, and duration of all storms in a year, as well as threshold numbers of tropical storms and hurricanes per season, to categorize hurricane seasons into 3 groups: above normal, near normal, and below normal.

Source: National Interagency Fire Center; National Oceanic Atmospheric Administration

In other ways, too, utilities are already more vulnerable to extreme weather events than in the past. When homes are built in areas prone to wildfires, power companies follow, placing their own assets at higher risk. These can even exacerbate the problem, if sparks from power lines ignite. Fires also emit additional carbon dioxide (CO_2), a greenhouse gas that contributes to climate change. In California, the devastating 2018 fire season emitted approximately 15 percent of the CO_2 California emits from all sources in a typical year.

If climate change brings significant sea-level rise, as many models predict, that raises new vulnerabilities, but the risk is material today. In the United States, nine nuclear-power plants are located within two miles of the ocean. Many of the nation's 8,625 power plants were deliberately sited near shorelines in order to have access to water. As a result, when hurricanes strike, power plants already face significant flooding damage.

According to the Department of Energy, 44 power plants were in flooded areas in Hurricane Irene and 69 were in flooded areas in Hurricane Sandy. During these hurricanes, eight nuclear power plants had to shut down or reduce service. During Houston's Hurricane Harvey in 2017, wind and catastrophic flooding knocked down or damaged more than 6,200 distribution poles and 850 transmission structures; 21.4 gigawatts of generation were affected by wind damage, flooding damage, fuel supply issues, or evacuations and shutdowns. If sea levels rise, storm surges would hit further inland, causing more damaging coastal flooding to generation, transmission, and distribution infrastructure.

Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage and upgrading infrastructure after the fact is expensive and traumatic. Hurricane Katrina in 2005 forced Entergy New Orleans into Chapter 11 bankruptcy reorganization. There are, of course, compelling environmental and social reasons to invest in mitigation efforts sooner rather than later. We believe there are also economic ones. Power utilities need to invest on the basis that the present is already riskier than what was planned and the future will be more volatile. There is evidence that climate change adaptation can also be cost-effective.

The benefits of being prepared

In order to understand the economics of mitigating climate-change risk in the United States, we considered the effect of extreme storms, largely hurricanes, on utilities, because it is relatively easy to measure storm-related impacts. To do so, we examined the financial records of ten large power utilities in seven states where hurricanes are common (Alabama, Florida, Georgia, Louisiana, North Carolina, South Carolina, and Texas), plus New Jersey, where hurricanes are less common but dense coastal populations mean damage from storms can be particularly costly.

According to this analysis, a typical utility saw $1.4 billion in storm-damage costs and lost revenues due to outages caused by storms over a 20-year period. Then, using estimates from the Fourth National Climate Assessment for increases in extreme weather events and coastal infrastructure damage driven by climate change, we estimated that by 2050, the cost of damages and lost revenues would rise by 23 percent ($300 million), or approximately two to three additional years with major hurricane damage. (These projected increases are conservative; they are based on estimates of regional increases in extreme weather or storm damage due to sea-level rise.) Combined, these estimates give us a baseline: $1.7 billion in economic damage for each utility by 2050.

Next, we looked at how much utilities have spent on programs to make their assets more resilient. We estimate it would take $700 million to $1 billion for a typical Southeastern US utility to prepare for impacts related to climate change. That is less than current 20-year storm costs of $1.4 billion and much less than the projected future storm costs of $1.7 billion. While each utility's cost-benefit calculation will differ based on its unique risk exposure profile and infrastructure costs, our

conclusion is that it pays to prepare for extreme weather (Exhibit 2). There are also likely to be ancillary benefits, such as improved reliability and enhanced diversity of supply.

This analysis only looks at the threat of increased storm damage to these ten utilities as a potential future cost; the National Climate Assessment notes that utilities could also see negative impacts from increased temperatures and heat waves, as well as sea-level rise even in the absence of storms. This will increase the financial costs to utilities of climate change and increase the benefits of being prepared.

How to improve preparedness and resiliency

Many power utilities in the United States have already started taking steps in this direction. There are different ways for them to adapt, depending on their geographic circumstances and natural endowments. Even so, we find that these efforts are clustered around the following themes:

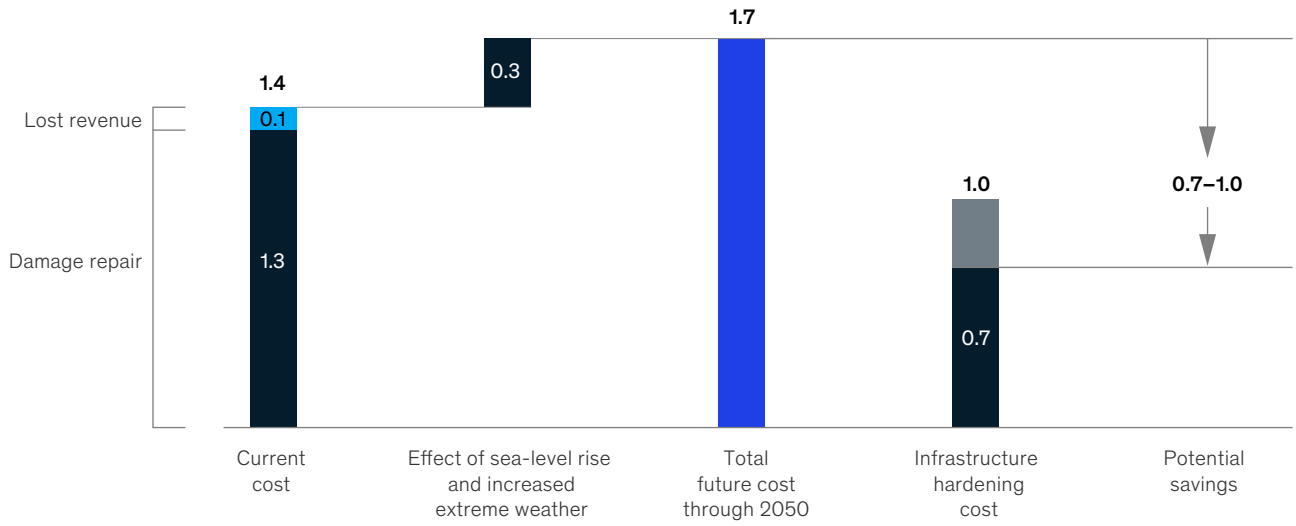
Harden the grid. This term refers to reinforcing the transmission and distribution (T&D) infrastructure to prevent or reduce the damage from extreme weather events. There are many examples. New Orleans Entergy, which lost 95 out of 125 miles of transmission lines during Hurricane Katrina, has invested $1 billion to improve the resilience of the substations and T&D lines, to ensure that they can withstand a storm of similar magnitude.

Similarly, after Superstorm Sandy hit the Northeast in September 2012, ConEd spent $1 billion and four years to strengthen its infrastructure. The utility installed distributed and elevated adjustable relay

Exhibit 2

Taking action on resiliency can be cost-effective, especially when future climate-change risks are taken into account.

20-year storm-damage costs compared with adaptation costs for a Southeastern utility,[1] $ billion



20% Current probability of experiencing storm damage in a given year

23% Projected increase in utility storm damage costs by 2050

[1] Estimated costs for a typical Southeastern utility.

Source: Energy Information Administration; National Climate Assessment; utility financial statements

panels; elevated control houses; ensured all new equipment in flood zones will be able to function if submerged; strengthened overhead lines; and added capabilities to allow isolation of parts of the grid in order to reduce the number of customers affected by damage to one section.

Florida Power & Light (FPL) embarked on a long-term grid-hardening program after Hurricane Wilma caused extensive damage in 2005. FPL spent more than $3 billion on flood protection, distribution feeder reinforcement, and replacing wood poles with steel or concrete structures, among other programs. FPL has also buried power lines underground in select areas, as have other utilities, though the cost-benefit analysis of doing so is mixed.

These investments are relatively recent. Moreover, the timescales are extended and long-term effects are therefore difficult to calculate. It is too early to know, then, whether these efforts will work as intended. What can be said is that in each case, different utilities chose a similar strategy and that their infrastructure is stronger as a result.

Explore nonwire options that go beyond hardening the grid. Grid hardening is expensive, and even an extensive program may not be enough to cope with the most extreme events. After completing much of its $3 billion grid-hardening program, for example, FPL still suffered more than $1 billion in damage during Hurricane Irma in 2017. There are other ways to build resilience and adaptability. Here are some possibilities:

— **Decentralizing generation.** Locating smaller, utility-scale facilities closer to population centers can reduce reliance on long transmission lines that are vulnerable to damage during storms. It also means that if one facility goes down, others still keep going. FPL, for example, is beginning construction on four new solar plants. While economics and FPL's clean-energy strategy played a large role in the decision, one of the installations in Miami–Dade county is explicitly designed as part of a resiliency strategy to provide more local generation.

— **Battery storage.** Batteries can provide backup power in the case of outages caused by storms and help utilities meet spikes in power demand. In 2017, Duke Energy announced a plan to invest $30 million to install North Carolina's largest battery-energy storage system to provide back-up power and improve grid reliability. In 2018, Duke increased the investment to $500 million over 15 years. In addition to providing enhanced reliability to the grid, these investments have already enabled the deferral of the construction of a new gas-peaker plant and allowed the utility to integrate larger amounts of renewable power into its mix.

The world's biggest lithium-ion battery was installed in the state of South Australia in 2017 near the Hornsdale Wind Farm; the $63.25 million project was intended to support its main power grid during peak summer demand and to help integrate renewable energy. In 2018, the first full year of operation, the system brought in $20.7 million in revenues.

— **Microgrids.** A microgrid is a set of locally controlled loads and distributed-generation resources that can function apart from the centralized grid. A microgrid can power a specific site, such as a jail, campus, or office building; utilities can deploy them to provide backup power in the event of power outages on the central grid. Batteries can also provide power to microgrids.

After Hurricane Irene knocked out power to many Connecticut residents in 2011, the state began encouraging the formation of microgrids to improve resiliency. Subsequently, the town

of Fairfield launched a microgrid for its critical infrastructure services, including its police department, fire department, communications center, and homeless shelter. While no storm has knocked out power to the main grid since installation, the town estimates the combined heat-and-power microgrid has saved the town an estimated $60,000 a year in electric expenses and $10,000 in heating expenses during normal operations—an example in which improving resiliency can be cost-effective.

— **Environmental management.** Active management of the natural environment can provide utilities and other infrastructure owners with protection against extreme weather. For example, coastal wetlands provide a natural barrier to lessen the impact of extreme storms. A recent study estimated that New Jersey's coastal marshes reduce flood damage by 16 percent during normal storm years, and that after Hurricane Sandy in 2012, the presence of wetlands and marshes up and down the east coast reduced hurricane damage by 27 percent.

In 2015, Entergy and other Gulf Coast companies began a pilot program to restore coastal wetlands in Louisiana to provide storm protection. The effort can also be counted as an offset to the companies' carbon emissions, since wetlands act as a carbon sink, providing a direct financial benefit.

The Alabama Power Company has constructed wetlands near its generation facilities; these also serve as filtration systems to remove chemicals from the water used in power-plant cooling.

Factor an up-to-date view of risk into operations. Utilities should consider the increased risk from climate change predicted by the Fourth National Climate Assessment and other reports as they examine their daily operations, not just when they are considering long-term investments. In a 2019 filing before the California Public Utilities Commission, Southern California Edison proposed changes to its operations to reflect its acknowledgement of the increased risk of wildfires. These measures include the increased monitoring of electrical equipment, clearing trees that pose a wildfire risk, and enhancing situation-awareness capabilities to allow for rapid emergency response, as well as prioritization of investments based on which locations are at greatest risk of wildfires.

Look for new partners to help develop and finance resiliency strategies. Utilities can work with insurers and reinsurers to assess climate risk and adaptation strategies. The latter can then help them underwrite those risks after the utilities have made agreed-upon investments in modernizing their infrastructures. In developing the Gulf Coast resiliency report, for example, Entergy worked with Swiss Re to develop regional models for climate risk assessment.

Public–private partnerships are another way to finance new investments in resiliency (see sidebar, "The role of regulation"). One effort in Colorado is creating a demonstration solar panel and battery-storage microgrid outside Denver. In the event of an outage, the microgrid would automatically be switched on, with power provided by an intelligent rooftop photovoltaic battery system to keep critical services running. The project is also intended to improve the integration of renewable energy and to cope with peak demand.

Finally, research institutions can help apply new ideas and strategies to a specific utility's context. For example, the Natural Capital Project—a partnership among Stanford University, the Chinese Academy of Sciences, the University of Minnesota, the Stockholm Resilience Centre, the World Wildlife Fund, and the Nature Conservancy—works with stakeholders to develop plans and stimulate investment in developments that improve resiliency through nature-based projects.

The role of regulation

Climate change could burden utilities with substantial costs above and beyond the damage caused by a particular event. In some jurisdictions, utilities can be held responsible for lost economic output caused by power outages. These assessments are, of course, ultimately borne by consumers, in the form of higher rates. A decade after Hurricane Katrina, Gulf Coast consumers were still paying storm damage charges.

Given their capabilities and knowledge, regulators are well positioned to work with utilities to help them make cost-effective investments in resiliency. Regulators can incentivize utilities to develop climate-adaptation plans that protect and upgrade their infrastructure. They can design liability structures that encourage utilities to take preventive actions by shifting the liability burden if specific measures are taken. And they can encourage experimentation and forward thinking. Regulators will have to define their priorities based on their specific circumstances, such as the state of their grid and generating system.

An example of resiliency-oriented regulation comes from Florida. Since 2006, the Florida Public Service Commission has required investor-owned power utilities to devise three-year storm-protection plans. The commission has also required utilities to implement aggressive vegetation management and an inspection program with an eight-year life cycle for wooden poles. Some utilities, for example, have replaced those poles with concrete structures designed to withstand 140 mile-per-hour winds.

These and other ideas must be stress tested and analyzed to ensure they are appropriate for specific circumstances. But the point is to begin considering them.

Utilities are asset-heavy businesses that must maintain extensive and expensive infrastructures. Unless they become more resilient to extreme weather, those assets will be vulnerable—and so will the utilities. They are not, however, helpless before climactic impacts. They can prepare. Not only does this make good sense, it is good business.

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The authors wish to thank Romina Mendoza and Jinchen Zou for their contributions to this article.

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Board Staff Interrogatory #41

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 33
Exhibit A2 / Tab 3 / Schedule 1 / Attachment 6 / p. 5

On page 33 of the Concentric Report, Concentric stated:

> 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 [later in the report]) and incremental inflationary risk.

On page 5 of Exhibit A2 / Tab 3 / Schedule 1 / Attachment 6, Moody's Investor Services (Moody's) stated:

> On November 10, 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2021-2026 at the 2021 based regulated price. While this provides price certainty for the period, it may be challenging for OPG to earn its allowed returns over the period given ongoing investments in rate base assets during the period that exceed depreciation.

Question(s):

a) Please provide quantitative estimates of the additional "operational risks and regulatory risks related to [OPG's] prescribed hydroelectric facilities" for each of:

   i. Climate change

   ii. Incremental inflationary risk due to the Hydroelectric payment price freeze from 2021 to 2026

   If this is not possible, please explain.

Response

Witness Panel: Finance and D&V Accounts

Response prepared by Concentric Energy Advisors

Concentric's approach did not estimate a specific quantitative impact of the risks identified in Ex. C1-1-1, Attachment 1. In Concentric's opinion, such an estimation would require numerous assumptions and provide the OEB with a false sense of precision regarding OPG's risk profile. Concentric's approach is necessarily qualitative, consistent with approaches employed by credit/equity analysts, cost of capital analysts, and regulators in assessing the risk profiles of utility companies.

Board Staff Interrogatory #42

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Attachment 1 / p. 3
Régie de l'énergie / Décision D-2003-93 R-3492-2002 / May 21, 2003[1]
Régie de l'énergie / Decision D-2014-034 R-3842-2013 / March 4, 2014[2]
Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume V, May 25, 2017 (revised)[3]

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> 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. *[Emphasis added]*

OEB staff notes that Concentric has periodically issued short reports summarizing the allowed ROEs for utilities in Canadian jurisdictions and comparing them also against the allowed ROEs for U.S. utilities. The most recent report available on Concentric's website is Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume V, May 25, 2017 (revised). On page 4 of this report, Concentric documents an ROE of 8.20% for Hydro-Québec TransÉnergie for every year from 2015 to 2017, and with a deemed equity thickness of 30%.
OEB staff understands that Hydro-Québec (Distribution) has a deemed equity thickness of 35% and Hydro-Québec (Transmission) has a deemed equity thickness of 30%, with both deemed equity thicknesses determined in a 2003 Régie de l'énergie Décision. The allowed ROE of 8.20% was set in early 2014 based on a decision of the Régie de l'énergie. OEB staff understands that the allowed ROE for Hydro-Québec has not been changed since.

Question(s):

[1] Régie de l'énergie / Décision D-2003-93 R-3492-2002, 21 mai 2003.
[2] Régie de l'énergie / Decision D-2014-034 R-3842-2013, 4 mars 2014.
[3] This document is attached as Appendix A to OEB staff's interrogatories.

a) If Concentric has prepared an updated report on allowed ROEs for Canadian and U.S. utilities since the May 25, 2017 report, please file a copy.

b) Please confirm or correct OEB staff's understanding that Hydro-Québec's allowed ROE continues to be 8.20%.

Response

Response prepared by Concentric Energy Advisors

a) Concentric has not published an updated report since May 2017, but we do maintain this database. The most recent data collected by Concentric is provided as L1-C1-01-Staff-042, Attachment 1.

b) Confirmed. As a point of clarification, and as indicated in response to L-C1-01-SEC-021, one jurisdiction is lower (than Ontario) for a government owned transmission and distribution utility, Hydro Quebec. The authorized ROE for both HQD and HQT is 8.20%. Hydro-Quebec's generation business is not regulated by the Régie and does not have a deemed equity ratio or an authorized ROE. In addition, the company's debentures and medium-term notes are guaranteed unconditionally by the Quebec government.

Authorized Rate of Return on Common Equity												
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Electric Distribution												
ATCO Electric Ltd.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
ENMAX Power Corporation	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
EPCOR Distribution Inc.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
FortisAlberta Inc.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
FortisBC Inc.	9.90	9.90	9.90	9.15	9.15	9.15	9.15	9.15	9.15	9.15	9.15	9.15
Maritime Electric Company Limited	9.75	9.75	9.75	9.75	9.75	9.75	9.35	9.35	9.35	9.35	9.35	9.35
Newfoundland Power Inc.	9.00	8.38	8.80	8.80	8.80	8.80	8.50	8.50	8.50	8.50	8.50	8.50
Nova Scotia Power Inc.	9.35	9.35	9.20	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Ontario's Electricity Distributors (Rates Effective May 1)	9.85	9.58	9.12	8.98	9.36	9.30	9.19	8.78	9.00	8.98	8.52	8.34
AVERAGE	**9.32**	**9.11**	**9.09**	**8.76**	**8.81**	**8.80**	**8.71**	**8.75**	**8.78**	**8.78**	**8.72**	**8.70**
MEDIAN	**9.00**	**8.75**	**8.80**	**8.80**	**8.80**	**8.80**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**
Hydro-Québec Distribution	7.85	7.32	6.37	6.19	8.20	8.20	8.20	8.20	8.20	8.20	8.20	8.20
Manitoba Hydro	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Newfoundland and Labrador Hydro	4.47	4.47	4.47	4.47	*4.47*	*8.80*	8.50	8.50	8.50	8.50	8.50	8.50
Saskatchewan Power Corporation	8.50	7.40	7.40	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
AVERAGE	**6.94**	**6.40**	**6.08**	**6.39**	**7.06**	**8.50**	**8.40**	**8.40**	**8.40**	**8.40**	**8.40**	**8.40**
MEDIAN	**7.85**	**7.32**	**6.37**	**6.19**	**8.20**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**
Electric Transmission												
AltaLink Management Ltd.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
ATCO Electric Ltd.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
ENMAX Power Corporation	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
EPCOR Transmission Inc.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
AVERAGE	**9.00**	**8.75**	**8.75**	**8.30**	**8.30**	**8.30**	**8.30**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**
MEDIAN	**9.00**	**8.75**	**8.75**	**8.30**	**8.30**	**8.30**	**8.30**	**8.50**	**8.50**	**8.50**	**8.50**	**8.50**
British Columbia Transmission Corporation	11.42	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Hydro One Networks Inc.	8.39	9.66	9.42	8.93	9.36	9.30	9.19	8.78	9.00	8.98	8.52	8.34
Hydro-Québec TransÉnergie	7.59	7.14	6.39	6.41	8.20	8.20	8.20	8.20	8.20	8.20	8.20	8.20
AVERAGE	**9.13**	**8.40**	**7.91**	**7.67**	**8.78**	**8.75**	**8.70**	**8.49**	**8.60**	**8.59**	**8.36**	**8.27**
MEDIAN	**8.39**	**8.40**	**7.91**	**7.67**	**8.78**	**8.75**	**8.70**	**8.49**	**8.60**	**8.59**	**8.36**	**8.27**
Natural Gas Distribution												
AltaGas Utilities Inc.	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
ATCO Gas	9.00	8.75	8.75	8.30	8.30	8.30	8.30	8.50	8.50	8.50	8.50	8.50
Enbridge Gas Inc.	8.39	8.39	8.39	8.93	9.36	9.30	9.19	8.78	9.00	8.98	8.52	8.34
Liberty Utilities Gas New Brunswick	13.00	10.90	10.90	10.90	10.90	10.90	10.90	10.90	10.90	10.90	10.90	10.90
FortisBC Energy Inc.	9.50	9.50	9.50	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
FortisBC Energy (Vancouver Island) Inc.	10.00	10.00	10.00	9.25	9.25	n/a	n/a	n/a	n/a	n/a	n/a	n/a
FortisBC Energy (Whistler) Inc.	10.00	10.00	10.00	9.50	9.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gaz Métro Limited Partnership	9.20	9.09	8.90	8.90	8.90	8.90	8.90	8.90	8.90	8.90	8.90	8.90
Gazifère inc.	8.89	9.10	8.29	7.82	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
Heritage Gas Limited	13.00	13.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
Pacific Northern Gas Ltd.	10.15	10.15	10.15	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.90	9.90	9.90	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25	9.25
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	10.15	10.15	10.15	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50
Union Gas Limited	8.54	8.54	8.54	8.93	8.93	8.93	8.93	8.93	8.93	n/a	n/a	n/a
AVERAGE	**9.91**	**9.73**	**9.52**	**9.20**	**9.32**	**9.31**	**9.30**	**9.30**	**9.32**	**9.35**	**9.31**	**9.29**
MEDIAN	**9.70**	**9.70**	**9.70**	**9.09**	**9.25**	**9.18**	**9.15**	**9.02**	**9.05**	**9.10**	**9.10**	**9.10**
Centra Gas Manitoba Inc.	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
SaskEnergy Inc.	8.75	8.75	8.75	8.75	8.75	8.75	8.30	8.30	8.30	8.14	8.14	
AVERAGE	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**	**8.30**	**8.30**	**8.30**	**8.14**	**8.14**	**n/a**
MEDIAN	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**	**8.30**	**8.30**	**8.30**	**8.14**	**8.14**	**n/a**

Authorized Common Equity Ratio												
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Electric Distribution												
ATCO Electric Ltd.	39.00	39.00	39.00	38.00	38.00	38.00	37.00	37.00	37.00	37.00	37.00	37.00
ENMAX Power Corporation	41.00	41.00	41.00	40.00	40.00	40.00	36.00	36.00	37.00	37.00	37.00	37.00
EPCOR Distribution Inc.	41.00	41.00	41.00	40.00	40.00	40.00	37.00	37.00	37.00	37.00	37.00	37.00
FortisAlberta Inc.	41.00	41.00	41.00	40.00	40.00	40.00	37.00	37.00	37.00	37.00	37.00	37.00
FortisBC Inc.	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Maritime Electric Company Limited	40.00	42.70	41.70	43.50	43.10	41.90	40.90	40.00	40.00	40.00	40.00	40.00
Newfoundland Power Inc.	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00
Nova Scotia Power Inc.	40.00	40.00	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50
Ontario's Electricity Distributors	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
AVERAGE	**40.78**	**41.08**	**40.69**	**40.44**	**40.40**	**40.27**	**38.93**	**38.83**	**38.94**	**38.94**	**38.94**	**38.94**
MEDIAN	**40.00**	**41.00**	**41.00**	**40.00**	**40.00**	**40.00**	**37.50**	**37.50**	**37.50**	**37.50**	**37.50**	**37.50**
Newfoundland and Labrador Hydro	20.00	20.00	20.00	20.00	20.00	25.20	25.20	25.20	25.20	25.20	25.20	25.20
Hydro-Québec Distribution	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
Manitoba Hydro	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00		
Saskatchewan Power Corporation	40.00	40.00	40.00	40.00	40.00	25.00	25.00	25.00	25.00	25.00	25.00	
AVERAGE	**30.00**	**30.00**	**30.00**	**30.00**	**30.00**	**27.55**	**27.55**	**27.55**	**27.55**	**27.55**	**28.40**	**30.10**
MEDIAN	**30.00**	**30.00**	**30.00**	**30.00**	**30.00**	**25.10**	**25.10**	**25.10**	**25.10**	**25.10**	**25.20**	**30.10**
Electric Transmission												
AltaLink Management Ltd.	36.00	37.00	37.00	36.00	36.00	36.00	37.00	37.00	37.00	37.00	37.00	37.00
ATCO Electric Ltd.	36.00	37.00	37.00	36.00	36.00	36.00	37.00	37.00	37.00	37.00	37.00	37.00
ENMAX Power Corporation	37.00	37.00	37.00	36.00	36.00	36.00	36.00	36.00	37.00	37.00	37.00	37.00
EPCOR Transmission Inc.	37.00	37.00	37.00	36.00	36.00	36.00	37.00	37.00	37.00	37.00	37.00	37.00
AVERAGE	**36.50**	**37.00**	**37.00**	**36.00**	**36.00**	**36.00**	**36.75**	**36.75**	**37.00**	**37.00**	**37.00**	**37.00**
MEDIAN	**36.50**	**37.00**	**37.00**	**36.00**	**36.00**	**36.00**	**37.00**	**37.00**	**37.00**	**37.00**	**37.00**	**37.00**
British Columbia Transmission Corporation	40.70	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	n/a	n/a	n/a	n/a	n/a
Hydro One Networks Inc.	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Hydro-Québec TransÉnergie	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
AVERAGE	**36.90**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**
MEDIAN	**40.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**	**35.00**
Natural Gas Distribution												
AltaGas Utilities Inc.	43.00	43.00	43.00	42.00	42.00	42.00	41.00	41.00	39.00	39.00	39.00	39.00
ATCO Gas	39.00	39.00	39.00	38.00	38.00	38.00	37.00	37.00	37.00	37.00	37.00	37.00
Enbridge Gas Inc.	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00
Liberty Utilities Gas New Brunswick	50.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00
FortisBC Energy Inc.	40.00	40.00	40.00	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50
FortisBC Energy (Vancouver Island) Inc.	40.00	40.00	40.00	41.50	41.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a
FortisBC Energy (Whistler) Inc.	40.00	40.00	40.00	41.50	41.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gaz Métro Limited Partnership	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50	38.50
Gazifère inc.	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Heritage Gas Limited	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00
Pacific Northern Gas Ltd.	45.00	45.00	45.00	46.50	46.50	46.50	46.50	46.50	46.50	46.50	46.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	40.00	40.00	40.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	40.00	40.00	40.00	46.50	46.50	46.50	46.50	46.50	46.50	46.50	46.50	46.50
Union Gas Limited	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	36.00	n/a	n/a	n/a
AVERAGE	**40.89**	**40.54**	**40.54**	**41.14**	**41.14**	**41.08**	**40.92**	**40.92**	**40.75**	**41.18**	**41.18**	**41.18**
MEDIAN	**40.00**	**40.00**	**40.00**	**41.25**	**41.25**	**40.50**	**40.50**	**40.50**	**39.50**	**40.00**	**40.00**	**40.00**
Centra Gas Manitoba Inc.	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
SaskEnergy Inc.	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00
AVERAGE	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**
MEDIAN	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**	**33.50**

Board Staff Interrogatory #43

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Exhibit A2 / Tab 2 / Schedule 1

Preamble:

On page 2 of Exhibit A2 / Tab 2 / Schedule 1, OPG stated that the 2020-2026 Business Plan covers a range of important events and initiatives for OPG's regulated generating facilities, including:

- Successfully executing the DRP and positioning the Darlington NGS for strong post-refurbishment performance
- Optimizing the remaining operating life of Pickering NGS in a safe, reliable, and economically effective manner
- Achieving a post-Pickering cost structure that mitigates, to a significant extent, the diseconomies of scale that will result within OPG from the Pickering NGS shutdown
- Where possible, minimizing the impact of transitioning the workforce to a post-Pickering organization, with an expected reduction of over 3,000 employees following the station's shutdown
- Investing in continued reliability, resilience and value of the regulated hydroelectric fleet

In its evidence, Concentric points to risks that OPG faces during the term plan, particularly towards the end of the plan term in 2025 and 2026, in support of its proposed 50% equity thickness. Specifically, Concentric stated, on page 1 of the Concentric Report:

> 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.

Question(s):

a) Can Concentric provide a quantitative assessment of the importance of each of the factors it cited as reasons for its assessment of increasing risk in the quoted paragraph above? At a minimum, can Concentric provide a ranking of the importance of each of these factors in Concentric's assessment of increased regulatory risk for OPG during 2022-2026? If not, please explain.

b) On page 16 of Exhibit A2 / Tab 2 / Schedule 1, OPG stated that OPG does not seek recovery of costs arising from any Pickering NGS closure activities in this application and will record them in the Pickering Closure Cost Deferral Account pursuant to O. Reg. 53/05.

   i. Please identify whether, and if so, how, the availability for the recording of certain costs in the Pickering Closure Cost Deferral Account has been taken into account in Concentric's analysis of OPG's business risk and the commensurate equity thickness.

   ii. Can Concentric provide examples of analogous DVAs for asset decommissioning or retirement costs in the comparator utilities used in its analysis? If so, please identify such analogous examples.

Response

Response prepared by Concentric Energy Advisors

a) As described in Ex. C1-1-1, Attachment 1, p. 6, Concentric concludes that, based on the totality of the risk factors discussed in Ex. C1-1-1, Attachment 1, there has been a shift in OPG's risk profile since the time of EB-2016-0152 that is sufficient to warrant a reassessment of OPG's equity ratio. Concentric did not, however quantify the explicit risk increments owing to each individual risk factor discussed. In terms of a rough order of magnitude, Concentric estimates that the risks faced by the Company related to the investment in, and operations of, its nuclear fleet (the DRP and the retirement of Pickering) are the most significant risks faced by OPG in the upcoming rate setting period.

b) (i) As described in Ex. C1-1-1, Attachment 1, p. 47, OPG anticipates that it will incur a significant amount of severance and workforce transition costs related to the Pickering closure. Further, the report also notes that 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.

Concentric's report assumes that this mechanism will allow for the substantial full recovery of those costs by OPG, subject to a prudence review.

(ii) Concentric is not aware of any regulated nuclear plants that are owned by the comparator utilities that are nearing a planned retirement, and as such is not aware of any of those utilities establishing DVAs related to costs that might be analogous to the Pickering Closure Costs Deferral Account.

Concentric is aware that the U.S. utilities in the proxy group have external trust funds that are funded by ratepayers and are held in trust for the purposes of nuclear plant retirement and associated costs. Concentric is further aware of utilities that have established deferral mechanisms related to the closure of coal facilities. PNM Resources, Inc., for example, has recorded and been authorized to recover regulatory assets related to coal ash remediation, and has further been authorized to accelerate the depreciation expense recovered through rates of coal plants that are scheduled to retire earlier than their original end of life.

Board Staff Interrogatory #44

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 4
Exhibit A1 / Tab 4 / Schedule 2 / pp. 2-3 / Chart 1
Exhibit A1 / Tab 4 / Schedule 3 / p. 2 / Chart 1

Preamble:

On page 4 of the Concentric Report, Concentric stated:

> 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.

Chart 1 at Exhibit A1 / Tab 4 / Schedule 3 provides a summary of the capacity of the NGSs and units.

Chart 1 at Exhibit A1 / Tab 4 / Schedule 2 provides a summary of the capacity of the prescribed hydroelectric generating stations.

Question(s):

a) Please confirm that 60% refers to the number of nuclear generating units (6 in operation at Pickering NGS, 4 at Darlington NGS) and not to the generation capacity split between Pickering NGS and Darlington NGS.

b) Please confirm that, with the shutdown of Pickering NGS, the reduction in OPG's nuclear generation capacity, assuming all Darlington NGS units are available, would be to 3,512 MW of the current 6,606 MW, a reduction of approximately 47%.

c) OEB staff notes that not all of the hydroelectric generating capacity would be considered baseload, but the Saunders plant, most of the Niagara G.S., and certain other hydroelectric stations would function as baseload. However, please confirm that the generating capacity of OPG's prescribed hydroelectric generation assets, per Chart 1 at Exhibit A1 / Tab 4 / Schedule 2, is 6,423 MW.

d) Please confirm that OPG's regulated generation capacity is currently 6,423 MW + 6,606 MW = 13,029 MW, and that it will be 6,423 MW + 3,512 MW = 9,935 MW with the shutdown of Pickering NGS. Therefore, please confirm that the reduction in OPG's regulated generation capacity with the Pickering NGS shutdown after 2025 would be 23.75%.

e) During most of the 2017-2021 period, Unit 2 of the Darlington NGS was shut down for refurbishment, coming back into service in early 2020. Therefore, OPG's nuclear generation capacity during most of the current term was reduced by 934 MW from the overall capacity of 6,606 MW. OEB staff also notes that Pickering NGS's operational life has been extended, and that approval for Pickering Extended Operations was still being considered by the Canadian Nuclear Safety Commission (CNSC) at the time of OPG's 2017-2021 Payment Amounts Proceeding.

   i. Was there not a similar increased business risk at the time of the OPG's 2017-2021 Payment Amounts Proceeding that would have resulted from the loss of regulated nuclear generation capacity and of concentration of nuclear generation at Darlington NGS if Pickering Extended Operations was not approved by the CNSC?

   ii. Can Concentric substantiate, quantitatively if possible, what is the increased risk due to the inevitable shutdown of Pickering NGS during (and later in) the 2022-2026 plan period relative to the business risk of a potential shutdown that could have occurred during the 2017-2021 plan period absent CNSC approval?

Response

a) Confirmed.
b) Confirmed.
c) Confirmed.
d) Confirmed, absent any changes to OPG's regulated hydroelectric generation capacity. For example, OPG does expect nominal changes in the regulated hydroelectric generation capacity as a result of Calabogie GS returning to service as well as other capacity increasing projects.

Part e prepared by Concentric Energy Advisors

e) (i) To clarify, OPG's in-service generating capacity was reduced by 878 MW as a result of Unit 2 of the Darlington NGS being offline for refurbishment.

As Concentric noted in our report filed in EB-2016-0152, there were risks at that time associated with the re-licensing of the Pickering units to the end of the planned extended operation period, including the risk that there would be a future determination that extended operation of the plant is not feasible. While a risk at that time, however, there is more certainty of Pickering closure in the upcoming rate setting period than during the proceeding five years, increasing the level of attendant risk associated with the closure. Further, as noted in our report (at 44), due to the plant's increased age since EB-2016-0152, ongoing operating cost and generation revenue risks increase for a station operating closer to its ultimate shutdown date. As further noted in our report (at 49), "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."

(ii) Please see the response to part (d)(i). Concentric has not quantified the change in risk. See the response to I-C1-01-Staff-43 for further discussion.

Board Staff Interrogatory #45

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
EB-2016-0152 / Exhibit C1 / Tab 1 / Attachment 1
EB-2016-0152 / Decision and Order / December 28, 2017

Preamble:

In OPG's 2017-2021 Payment Amounts Proceeding, Concentric also filed similar evidence regarding the appropriate deemed capital structure for the 2017-2021 term. Concentric's evidence was also filed as Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 in that proceeding, and was titled Common Equity Ratio: For OPG's Regulated Generation.

OEB staff notes that, in OPG's 2017-2021 Payment Amounts Proceeding, Concentric relied on the increase in the proportion of OPG's regulated rate base that represented nuclear generation by the end of the 2017-2021 term as one key factor in its assessment of OPG's increased business risk in that plan term.[1] OEB staff notes that Concentric similarly relied on the proportions of OPG's regulated rate base accounted by nuclear generation, which increases over the 2022-2026 plan term as refurbished units at Darlington NGS re-enter service, as a major factor for its proposed equity thickness of 50%.[2]

Question(s):

a) Please identify any substantive changes in Concentric's approach or methodology used for preparing its report filed with this application compared with its evidence filed in OPG's 2017-2021 Payment Amounts Proceeding.

Response

Response prepared by Concentric Energy Advisors

Concentric's overall approach in the current proceeding, which involves a detailed assessment of OPG's business and financial risks and an analysis of an appropriate equity thickness for OPG based on a proxy group of comparable North American utilities, is generally consistent with our approach used in EB-2016-0152 and is further

[1] EB-2016-0152 / Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / May 2016 / p. 2.
[2] Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 7.

consistent with the framework by which the OEB has evaluated equity thickness. For instance, in its decision in EB-2016-0152, the OEB reviewed key areas of OPG's business risk and further found (at 107) that "The OEB accepts that the fair return standard requires that similar utilities be comparable in terms of equity thickness as well as return on equity" in its consideration of capital structure.

Concentric did, however, make certain adjustments to its approach based on the OEB's findings in EB-2016-0152 and other changes in OPG's business risk profile, including:

(1) providing further context regarding Canadian versus U.S. historical equity ratios, including a summary of interviews with equity and credit analysts;
(2) providing evidence regarding changes in capital markets since EB-2016-0152;
(3) analyzing an additional proxy group of companies found by Moody's Investors Service to be comparable to OPG;
(4) in addition to authorized equity ratios for the proxy groups (which were analyzed in EB-2016-0152), also providing evidence regarding actual holding company and utility operating company equity ratios; and
(5) considering the OEB's additional findings in EB-2016-0152 regarding relative production levels, in addition to rate base levels, as between nuclear and hydroelectric generation.

Board Staff Interrogatory #46

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 4-5

Preamble:

On page 4 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) In Figure 1 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 5, are the percentages shown for the percentage of OPG's regulated rate base composed of nuclear assets at December 31 or average annual / mid-year figures?

Response

a) The percentages shown in Figure 1 were determined using OPG's regulated rate base which, per Ex. B1-1-1 pp. 4-5, generally reflects the mid-year average methodology, except for in-service addition amounts of $50M or greater which are weighted in the first year based on their in-service month.

Board Staff Interrogatory #47

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 23

Preamble:

On page 23 of the Concentric Report, with respect to country risk, Concentric stated:

> They [equity and credit analysts] 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.

Question(s):

a) How do the deemed equity thickness and allowed equity returns in Ontario compare with those applied to regulated electricity sector assets in jurisdictions other than the U.S., such as Australia and the United Kingdom?

Response

Response prepared by Concentric Energy Advisors

Authorized ROEs and equity ratios are generally lower in the United Kingdom and Australia than in the U.S. or Canada. For example, in the U.K., OFGEM issued a decision in March 2021 under the second generation of its regulatory framework, known as RIIO-2. OFGEM set the cost of equity for utilities at 4.55% (real) based on a CAPM analysis. The debt ratio (referred to as "notional gearing" by OFGEM) was set at either 55% or 60%, depending on the specific utility. National Grid and other transmission cable operators, including Scottish Power and SSE, indicated that they intend to appeal OFGEM's decision, in part, because the authorized return is not sufficient. Concentric notes that OFGEM sets returns on a real basis, so they are not directly comparable to those set by the OEB. OFGEM's returns are also supplemented by significant performance incentives. Further, these rates of return only applied to regulated distributors. Generators participate in a competitive wholesale market, compensated for energy, capacity and contracts for differences, so there are no comparable allowed returns to OPG's in the U.K.

In Australia, the ROE and equity ratio were last set by the Australia Energy Regulator in 2018 and remain in effect until the return is set again in 2022. The ROE in 2018

was set at 6.36% based on the results of a CAPM analysis, down from 7.25% in 2013. The debt ratio (referred to as “gearing” by the AER) was set at 60%.

Australia has never had a nuclear power station, so there are no comparable regulated returns to OPG’s.

Board Staff Interrogatory #48

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 26

Question(s):

a) Please provide an update to Figure 4 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 26 by adding a column to the left of the "Source", and showing results for the full calendar year 2020.

Response

Response prepared by Concentric Energy Advisors

Chart 1: Capital Market Trends 2017-2020

	As Filed Values						
Description	2017	2018	2019	YTD 2020	Current (12/24/2020)	Full Year 2020	Source
TSX Index	15,545	15,738	16,317	15,999	17,624	16,029	[1]
S&P 500 Index	2,448	2,744	2,912	3,210	3,703	3,220	[1]
30-Year Bond Yield (Canadian)	2.28%	2.36%	1.80%	1.22%	1.26%	1.22%	[1]
30-Year Bond Yield (U.S.)	2.89%	3.11%	2.58%	1.56%	1.66%	1.56%	[1]
10-Year Bond Yield (Canadian)	1.79%	2.28%	1.59%	0.76%	0.72%	0.76%	[1]
10-Year Bond Yield (U.S.)	2.33%	2.91%	2.14%	0.89%	0.92%	0.89%	[1]
30-Year Utility Bond Yield (Canadian)	3.65%	3.74%	3.30%	2.78%	2.62%	2.78%	[1]
30-Year Utility Bond Yield (U.S.)	4.01%	4.25%	3.78%	2.99%	2.73%	2.99%	[1]
Real GDP Growth (Canadian)	3.04%	2.43%	1.86%	-6.18%	-3.44%	-5.40%	[2], [4]
Real GDP Growth (U.S.)	2.33%	3.00%	2.16%	-4.13%	-2.18%	-3.49%	[3], [4]

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
[4] "Full Year 2020" values reflect the 2020 four-quarter average divided by the 2019 four-quarter average

Board Staff Interrogatory #49

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 23-24

Preamble:

On pages 23-24 of the Concentric Report, Concentric discussed "influence of regulatory risk on investment analysis."

Question(s):

a) For companies that include a mix of regulated and unregulated assets, would Concentric characterize the unregulated assets as being more or less risky than the regulated assets? Please explain your response with reasons.

Response

Response prepared by Concentric Energy Advisors

Concentric believes that investors generally consider unregulated assets as being higher risk than regulated assets. As discussed on page 64 of our report, Concentric has screened the proxy group to include companies that have greater than 60 percent of revenue and net income from regulated operations and 80 percent of regulated revenue and net income from regulated electric operations. Most of these companies are 90% or higher in both regulated revenue and net income. The purpose of these screens is to select companies with a primary concentration in regulated electric utility operations. Further, Concentric has screened for companies that all have investment grade credit ratings. As Concentric concludes on page 77 of the report: "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." Taken further, all of the proxy companies have a lower risk profile than OPG, with its concentration in generation and nuclear power operations.

Board Staff Interrogatory #50

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 3, 27-28

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> 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.

On page 27 of the Concentric Report, Concentric stated:

> 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.

Concentric provided Figure 6 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28 and identified the utility betas as being sourced from Bloomberg.

Question(s):

a) With reference to the quote from page 3 of the Concentric Report, please describe what is meant by “historical norms” and how current observations differ.

b) Does Concentric consider that this departure from historical norms to be temporary (i.e. related to the COVID-19 pandemic) or permanent. Please provide the reasoning.

c) Please provide the data that Concentric has relied upon to produce Figure 6 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28. In the alternative, please provide exact references to the data series used from Bloomberg for the production of Figure 6.

Response

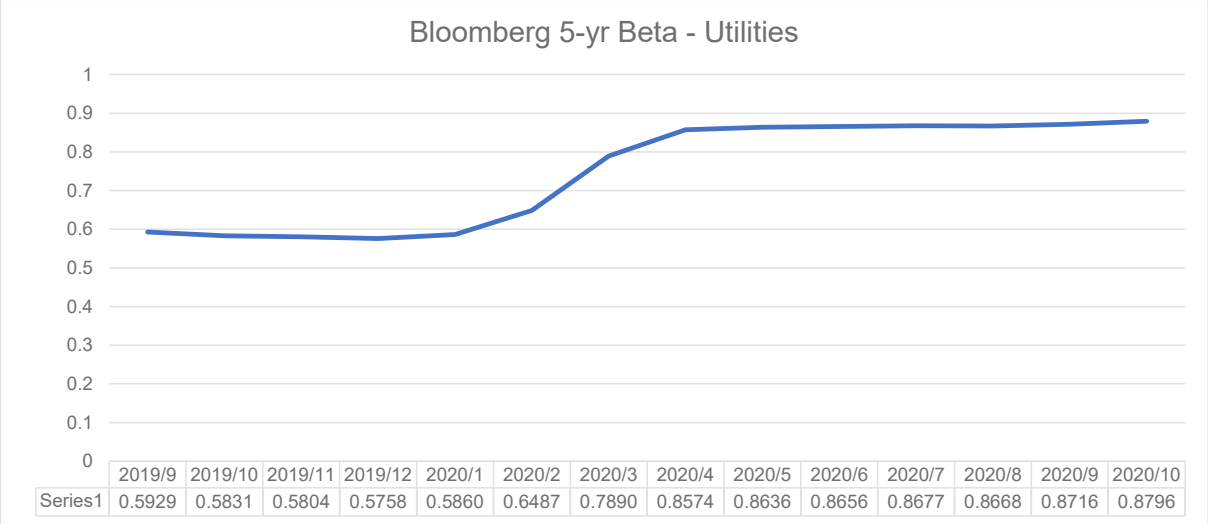
Response prepared by Concentric Energy Advisors

a. As discussed on pages 27-28 of Concentric's Report, Beta coefficients for regulated utilities increased substantially in March/April 2020. For example, as shown in Figure 6 on page 28 of Concentric's report, average Beta coefficients for regulated utilities ranged from 0.85 to 0.90 from March 2020 through October 2020, and have remained in that range through February 2021. By contrast, in the five months prior to the COVID-19 pandemic, average Beta coefficients for regulated utilities were around 0.60.

b. The Bloomberg Beta coefficients shown in Figure 6 of Concentric's Report are based on five years of historical stock prices measured on a weekly basis against the S&P 500 Index. While there is no way to know the duration of the COVID-19 pandemic, the fact that Betas calculated over a five year period have risen to this level suggests that the increase is more than just a short-term reaction to the pandemic.

c. Please see Chart 1 below

Chart 1



	2019/9	2019/10	2019/11	2019/12	2020/1	2020/2	2020/3	2020/4	2020/5	2020/6	2020/7	2020/8	2020/9	2020/10
Series1	0.5929	0.5831	0.5804	0.5758	0.5860	0.6487	0.7890	0.8574	0.8636	0.8656	0.8677	0.8668	0.8716	0.8796

Board Staff Interrogatory #51

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28

Preamble:

On page 28 of the Concentric Report, Concentric stated:

> The above trend [referring to Figure 6] 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.

Question(s):

a) Concentric indicates that because betas have increased, the cost of equity has increased. Based on the capital asset pricing model ("CAPM"), is it possible for the overall cost of equity to fall even if betas rise, provided the risk-free rate falls?

b) Does the OEB update the cost of capital more frequently than do regulators in U.S. jurisdictions? If so, does this mean that future allowed equity costs in the U.S. may fall if risk-free rates remain low?

c) If interest rates begin to rise, does Ontario's system of regular adjustments to the cost of equity provide a risk mitigant for regulated entities relative to what is the norm in many other Canadian and U.S. jurisdictions?

Response

Response prepared by Concentric Energy Advisors

a) While it is possible for the overall cost of equity estimate from the CAPM to decrease even if betas rise, that is not the case under current market conditions. The increase in betas for utilities since February 2020 has more than offset the decrease in government bond yields over that same period. As such, the CAPM analysis indicates that the cost of equity has increased for regulated utilities. In addition, Concentric notes that the yield on long-term Canadian bonds currently

exceed their pre-pandemic level (*i.e.*, 1.98% as of April 1, 2021 compared to 1.76% as of January 1, 2020).

b) Yes, the OEB's annual formula for the cost of capital is updated more frequently than most U.S. jurisdictions. Most Canadian and U.S. jurisdictions do not establish the authorized ROE for regulated utilities based on an annual adjustment formula. Rather, the ROE is set periodically (but typically not annually) based on an evaluation of current market data using a variety of financial models including the CAPM, discounted cash flow, risk premium, and expected earnings models. Numerous rate cases have been completed in the U.S. in the current low-interest rate environment, and average ROEs in the U.S. have fallen over time. Concentric expects that future determinations regarding the cost of capital will be based on a number of factors, including market conditions, evaluations of financial models, and consideration of credit spreads and company-specific business risks. As such, the cost of capital could be higher or lower, depending on those considerations.

c) The OEB's formula is updated annually based on changes in government and corporate bond yields, so an increase in interest rates would impact the next formula adjustment in Ontario. In terms of whether that provides a risk mitigant for Ontario utilities relative to non-Ontario utilities, this could be the case in the short-term, but Concentric notes that if interest rates increase, as they have since July 2020, utilities in most U.S. and Canadian jurisdictions may decide whether to file for a rate increase, assuming the utility is not subject to a rate freeze.

Board Staff Interrogatory #52

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
EB-2016-0152 / Exhibit C1 / Tab 1 / Attachment 1

Preamble:

On page 30 of its evidence filed in OPG's 2017-2021 Payment Amounts Proceeding, Concentric stated the following with respect to its selection of the comparator group for assessing OPG's appropriate capital structure:

> 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".

On page 31 of that evidence, Concentric noted that it reduced the comparator group to 10 U.S. utilities and two Canadian utilities in addition to OPG. On page 32, Concentric provided Figure 5 listing the utilities in the selected comparator group, along with Credit Rating Agency summary ratings.

On page 63 of the Concentric Report filed in the current proceeding, Concentric stated:

> 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."

Following on pages 65-66, Concentric noted that no other Canadian utility met all of Concentric's selection criteria. However, Concentric included three Canadian utilities (Algonquin, Emera and Fortis) who each met most of the criteria. On page 67, Concentric provided Figure 16, which shows the three Canadian utilities and 16 U.S. utilities that Concentric included in its proxy group.

OEB staff has prepared the following table comparing the selected utilities in Concentric's comparator groups in the studies in OPG's 2017-2021 Payment Amounts Proceeding and 2022-2026 Payment Amounts application.

Utility Name	**Included in Comparator Sample**	
	EB-2016-0152	**EB-2020-0290**
Ontario Power Generation Inc.	Yes	Yes

ALETTE Inc.	Yes	Yes
Algonquin Power and Utilities Corp.		Yes
Ameren Corporation	Yes	Yes
American Electric Power Company Inc.	Yes	Yes
Avista Corporation		Yes
Duke Energy Corporation	Yes	Yes
Edison International	Yes	Yes
El Paso Electric Company	Yes	Yes
Emera Inc.	Yes	Yes
Entergy Corporation	Yes	Yes
Evergy Inc.		Yes
Exelon Corporation		Yes
FirstEnergy Corporation	Yes	Yes
Fortis Inc.	Yes	Yes
Great Plains Energy Inc.	Yes	
IDACORP Inc.	Yes	Yes
NextEra Energy Inc.	Yes	Yes
PG&E Corporation	Yes	
Pinnacle West Capital Corporation	Yes	Yes
PNM Resources Inc.	Yes	Yes
Portland General Electric Company	Yes	Yes
Public Service Enterprise Group, Inc.		Yes
Southern Company	Yes	Yes
Westar Energy Inc.	Yes	
Xcel Energy Inc.	Yes	

Question(s):

a) Please confirm or correct the data shown in the table above.

b) Please explain the reasons for each utility added to, or removed from, the comparator group from OPG's 2017-2021 Payment Amounts Proceeding to the current application.

c) Other than what Concentric has documented in the two studies, are there any other changes that Concentric has made in the selection criteria for determining the comparator groups in the two studies?

Response

Response prepared by Concentric Energy Advisors

a) Please see Chart 1 below for a summary of the companies included in Concentric's proxy group in EB-2016-0152 and the current case. The table below also provides a brief explanation of the reason(s) each utility was added to, or removed from, Concentric's proxy group, if applicable.

Chart 1: Proxy Group Comparison

Company Name	Ticker	In Comparator Sample?		Explanation for Addition / Removal
		EB-2016-0152	EB-2020-0290	
ALLETE, Inc.	ALE	Yes	Yes	
Ameren Corporation	AEE	Yes	Yes	
American Electric Power Company, Inc.	AEP	Yes	Yes	
Avista Corporation	AVA	No	Yes	No longer fails the regulated electric revenue / income screens
Duke Energy Corporation	DUK	Yes	Yes	
Edison International	EIX	Yes	Yes	
El Paso Electric Company	EE	Yes	Yes	
Entergy Corporation	ETR	Yes	Yes	
FirstEnergy Corporation	FE	Yes	Yes	
Evergy, Inc.	EVRG	No	Yes	Reflects the merger of GXP and WR
Great Plains Energy Inc.	GXP	Yes	No	Due to merger activity, GXP became EVRG
IDACORP, Inc.	IDA	Yes	Yes	
NextEra Energy, Inc.	NEE	Yes	Yes	
PG&E Corporation	PCG	Yes	No	PCG's credit rating fell below investment grade
Pinnacle West Capital Corporation	PNW	Yes	Yes	
PNM Resources, Inc.	PNM	Yes	Yes	
Portland General Electric Company	POR	Yes	Yes	
Southern Company	SO	Yes	Yes	
Westar Energy, Inc.	WR	Yes	No	Due to merger activity, WR became EVRG
Xcel Energy Inc.	XEL	Yes	Yes	
Algonquin Power & Utilities Corp	AQN	No	Yes	Added to increase the number of Canadian utilities included in the proxy group
Emera Inc.	EMA	Yes	Yes	
Fortis Inc.	FTS	Yes	Yes	
Public Service Enterprise Group, Inc.	PEG	No	Yes	Added as part of Moody's proxy group
Exelon Corporation	EXC	No	Yes	Added as part of Moody's proxy group

b) Please see the response to part (a), above.

c) No.

Board Staff Interrogatory #53

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 34, 42, 71

Preamble:

On page 34 the Concentric Report, Concentric stated:

> 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.

On page 42 of the Concentric Report, Concentric provided a brief summary of examples from Florida, South Carolina and Georgia.

On page 71 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Is Concentric aware of any other North American utilities being charged for replacement power and / or other added costs when outages were longer than expected, or plants underperformed?

b) Please discuss treatment of costs associated with the accelerated retirement of the Crystal River Nuclear Plant in Florida. What proportion of costs were assumed by shareholders?

Response

Response prepared by Concentric Energy Advisors

a) North American utilities may incur replacement power and/or added outage costs when outages at regulated nuclear plants are longer than expected or plants underperform. Generally, however, such costs are not borne by shareholders and

are rather reflected in pass-through mechanisms for fuel costs (for other units running in place of the nuclear units) or for purchased power costs (for purchases from the ISO or other generators).

b) Duke Energy Florida (subsidiary of Duke Energy Corporation, together, "Duke") was the owner and operator of Crystal River Unit 3 ("Crystal River"). Duke retired Crystal River in February 2013 after finding multiple "delaminations" (or separations) in the Crystal River containment vessel following replacement of the facility's steam turbines during a station extended power uprate (a significant refurbishment project). Following an investigation by the Florida Public Service Commission ("FPSC") of the prudence of Duke's decision to retire Crystal River, the costs incurred to repair Crystal River, and the remaining balance in rate base of the facility, Duke entered a settlement agreement with the Florida Office of Public Counsel that resolved the FPSC's docket. The settlement agreement was approved by the FPSC in October 2013. Per a press release from Duke, the terms of the settlement included full recovery of Crystal River, not to exceed approximately $1.5 billion, including certain future costs (subject to a limited prudence review). In addition, the settlement included provisions that Duke would write-off $295 million of deferrals/regulatory assets related to Crystal River (in addition to $100 million refunded to customers per a prior settlement), offset by the acceleration of cash recovery of Crystal River deferral accounts/regulatory assets of $130 million. Duke also recorded charges related to two settlements with joint owners of Crystal River that totaled $103 million. Certain extended power uprate costs would continue to be recovered through Florida's Nuclear Cost Recovery Clause. Duke also received significant insurance recoveries ($835 million, $490 million of which was refunded to customers) related to the delamination.

Duke further discloses in its 2020 10-K, at 153, that it anticipates that accelerated decommissioning costs related to Crystal River will be covered by its Nuclear Decommissioning Trust Fund:

> "On May 29, 2019, Duke Energy Florida entered into a decommissioning Services Agreement for the accelerated decommissioning of Crystal River Unit 3 located in Citrus County, Florida, with ADP CR3, LLC and ADP SF1, LLC, each of which is a wholly owned subsidiary of Accelerated Decommissioning Partners, LLC (ADP), a joint venture between NorthStar Group Services, Inc. and Orano USA LLC. The agreement will allow for completion of the decommissioning of Crystal River Unit 3 by 2027, rather than 2074 as originally planned. Duke Energy Florida will also sell and assign the spent nuclear fuel, storage canisters, high-level waste and existing dry spent fuel storage installation and certain related assets, together with certain

> associated liabilities and obligations to ADP SF1, LLC. Duke Energy Florida expects that the assets of the Nuclear Decommissioning Trust Fund as of December 31, 2020, will be sufficient to cover the contract price. The U.S. Nuclear Regulatory Commission approved the transaction on April 1, 2020, and the FPSC issued an order approving the transaction on August 27, 2020. The transaction closed on October 1, 2020."

As such, there are no additional costs assumed by Duke's shareholders related to Crystal River.

Duke separately indicates in its 2020 10-K, at 72, that its nuclear decommissioning costs are recovered through retail and wholesale rates.

Board Staff Interrogatory #54

Interrogatory

Reference:
OPG's Green Bond Impact Report 2020[1]

Preamble:

On page 1 of OPG's 2020 Green Bond Impact Report, OPG stated:

> In Q2, on April 8, 2020, OPG issued a third and fourth green bond offering under its Medium Term Note Program. The issuance, totaling $1.2 billion, consisted of $400 million of senior notes maturing in April 2025 with a coupon interest rate of 2.89 percent and $800 million of senior notes maturing in April 2030 with a coupon interest rate of 3.22 percent.

Question(s):

a) Please describe OPG's experience in the issuance of Green Bonds. How does the cost of funds associated with the issuance of Green Bonds differ from the cost of funds issued without the Green Bond designation?

b) In Concentric's view, how does a firm's ability to issue Green Bonds affect the firm's cost of capital.

c) Has OPG's issuance of Green Bonds been factored into Concentric's analysis of its recommended equity thickness? Please explain your response.

Response

a) The Green Bond market continues to develop. There has been no significant difference in interest rate on Green Bonds versus non-Green bonds. However, recent investor interest in green / sustainable financing has suggested a very marginal (1 to 2 basis points) benefit to interest rate on these bonds going forward.

Parts b and c prepared by Concentric Energy Advisors

b) Concentric does not view the ability of a firm to issue Green Bonds to affect the firm's cost of capital that applies to its other investment requirements.

[1] https://www.opg.com/investor-relations/green-bonds/

c) No. Concentric does not consider OPG's issuance of green bonds to have materially changed the Company's business and financial risk profile since EB-2016-0152.

Board Staff Interrogatory #55

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 50

Preamble:

On page 50 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Does the emergence of environmental, social and governance criteria benefit OPG by increasing the relative attractiveness of lending to its zero-carbon emissions regulated asset portfolio?

Response

Response prepared by Concentric Energy Advisors

As discussed in the response to Ex. L-C1-01-SEC-30, Moody's discusses OPG's low carbon transition risk, which, all else equal, may increase the relative attractiveness of lending to OPG versus utilities with high levels of exposure to carbon emitting resources. There are other key environmental, social and governance considerations, however, that the investment community considers (such that all else is not equal). For instance, credit rating agencies and investors commonly refer to the environmental and safety risks associated with owning nuclear generation facilities. For example, on pages 18-19 of Moody's June 2017 Rating Methodology for Utilities (See Ex. L-C1-01-Staff-40), Moody's describes how it assesses generation and fuel diversity. Importantly, Moody's states that "[i]ssuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will

incur lower scores." OPG's generation depends on two sources – nuclear and hydroelectric.

Moody's defines Challenged generation sources on page 18 and Threatened generation sources on page 19. Among the Threatened sources of generation, Moody's includes "nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (such as those in Canada)." The Moody's report suggests that credit rating agencies are extremely sensitive to the risks associated with nuclear generation. There is no evidence that the emergence of ESG criteria has changed this perception among rating agencies or investors.

Also, Moody's in its Electric Utilities and Power Generators Carbon transition risk report highlights that "issuers scoring poorly for technology cost risk have fossil or nuclear capacity in areas where the cost of solar or onshore wind power is lower" (See Attachment 1). The same report also state that "Renewables will receive a score of 1.0 for policy regardless of where is plant is located. As a low-carbon technology, nuclear plants will receive a score of 2.0 for policy risk because they are not exposed to emissions reduction policies. But nuclear plants will not benefit from decarbonization policies to the same degree as renewable energy sources."

Also see the response to Ex. L-C1-01-SEC-036 for a response to a related question.

Filed: 2021-04-19, EB-2020-0290
Exhibit L-C1-01-Staff-055
Attachment 1, Page 1 of 18

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TABLE OF CONTENTS

Most generation owners are moderately positioned for the transition to a low-carbon economy 2
How we calculate CTA scores for power generation 4
Generation CTA scores by component 5
Overall CTA scores benefit from reduced carbon exposure of non-generation businesses 12
Appendix 13
Moody's related publications 16

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Electric Utilities and Power Generators – US

Carbon transition risk for power generation varies widely by issuer

» **Most generation owners are moderately positioned for the transition to a low-carbon economy.** Our carbon transition assessments (CTAs) of 51 US electric utilities and power generators that own generation assets show a wide range of positioning for the transition to a low-carbon economy. The median generation CTA score was CT-7, indicating moderate positioning for the carbon transition. NextEra Energy Partners LP (Ba1 stable) and Covanta Holding Corporation (Ba3 stable) received scores indicating advanced positioning because they do not use fossil fuels. Significant exposure to coal-fired generation leaves Ameren Corporation (Baa1 stable), DTE Energy Company (Baa2 stable) and NRG Energy Inc. (Ba1 positive) poorly positioned.

» **Overall CTA scores benefit from reduced carbon exposure of non-generation businesses.** The 51 issuers with generation assets were part of a broader cohort of 71 issuers in the power sector whose non-generation activities were also scored for transition risk. For our entire 71-issuer cohort, the median overall CTA score was CT-5, indicating strong positioning. Because most non-generation operations are less carbon-intensive than power generation, this mitigates transition risk for most issuers.

» **Component A - Current business profile: fossil-fuel plants result in exposure to expected phase out.** NextEra Energy Partners and Covanta received the strongest scores for fossil-fuel supply weighting because they do not own any fossil generation. Fourteen issuers operate their fossil plants at high utilization rates, indicating more efficient operations that are better positioned to survive.

» **Component B - Policy, market and technology risk: exposure varies by location and capacity mix.** NextEra Energy Partners, Avangrid Inc. (Baa1 negative), PG&E Corporation (Ba2 stable) and Consolidated Edison Inc. (ConEd, Baa2 stable) are best positioned in terms of policy risk because of their reliance on renewable energy sources. Issuers scoring poorly for technology cost risk have fossil or nuclear capacity in areas where the cost of solar or onshore wind power is lower.

» **Component C - Medium-term response activities: broad range of positioning in terms of expected fossil-fuel supply mix.** About 40% of the issuers are poorly positioned because of their expected reliance on fossil fuels through 2025.

» **Component D - Long-term resilience: significant realignment needed for some issuers under a rapid carbon transition.** About 30% of issuers are poorly positioned because a significant portion of their generation mix is coal that is at risk of retirement.

Most generation owners are moderately positioned for the transition to a low-carbon economy

Our carbon transition assessments (CTAs) for US electric utilities and power generators show a wide range of positioning for the sector's transition to a low-carbon economy. The 71 issuers we have scored in this report (see page 15) span a wide range of regulated and unregulated issuers involved in the generation and/or transmission of electric power. Of those issuers, 51 own generation assets that were scored under our CTA framework for power generation. The generation CTA scores for these issuers ranged from CT-1 to CT-9 on our 10-point CTA scale, where CT-1 shows the most advanced positioning and CT-10 the poorest. The median generation CTA score was CT-7, indicating moderate positioning for the carbon transition. This range of scoring reflects that the energy transition is already occurring. The new US Administration taking office in 2021 is expected to accelerate this trend.

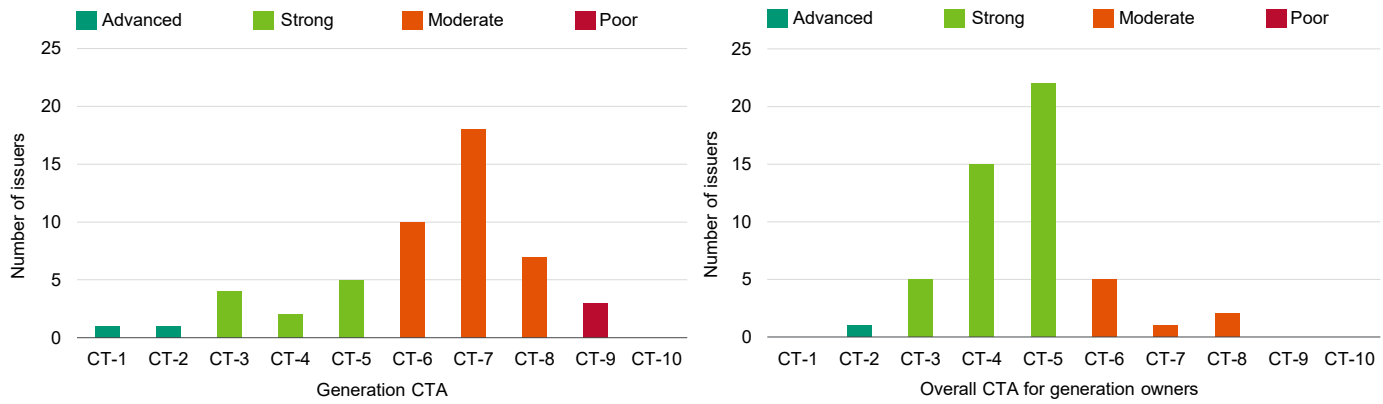
NextEra Energy Partners and Covanta were the only issuers to receive generation CTA scores that indicated advanced positioning for the carbon transition, buoyed by generation assets that are fueled by renewable sources (NextEra Energy Partners) or municipal waste (Covanta). Similarly, most of the generation assets owned by Avangrid and ConEd consist of wind and solar farms in their unregulated power segments, which improve their CTA positioning compared to their core distribution utility asset profile. At the other end of the spectrum, significant exposure to coal-fired generation contributed to CT-9 scores for Ameren, DTE and NRG, indicating poor positioning.

We also calculated separate scores for non-generation activities because most of the issuers in our cohort have a combination of generation, distribution, transmission and other related operations, all of which have varying levels of exposure to carbon transition risk. Most non-generation operations have lower levels of exposure to transition risk than power generation, as transmission and distribution is neutral to the type of power generated. As a result, the generation owners' final overall CTA scores, which reflect the aggregate transition risk of both their generation and non-generation operations, were generally stronger than their generation-only CTA scores (see Exhibit 1). The median overall CTA score for the 51 generation owners in our cohort was CT-5, indicating strong positioning for the carbon transition.

Exhibit 1

Generation owners' overall CTA scores were generally stronger than their generation-only CTA scores

Distribution of carbon transition assessment scores for the 51 generation owners in our cohort



Source: Moody's Investors Service

Most of the generation owners saw a one- to two-notch improvement in their overall CTA score, while issuers whose operations are most heavily weighted toward transmission and distribution or networks businesses, like American Electric Power Company (Baa2 stable), FirstEnergy Corp. (Ba1 negative), Ameren and PPL Corporation (Baa2 stable) had differentials of four to five notches.

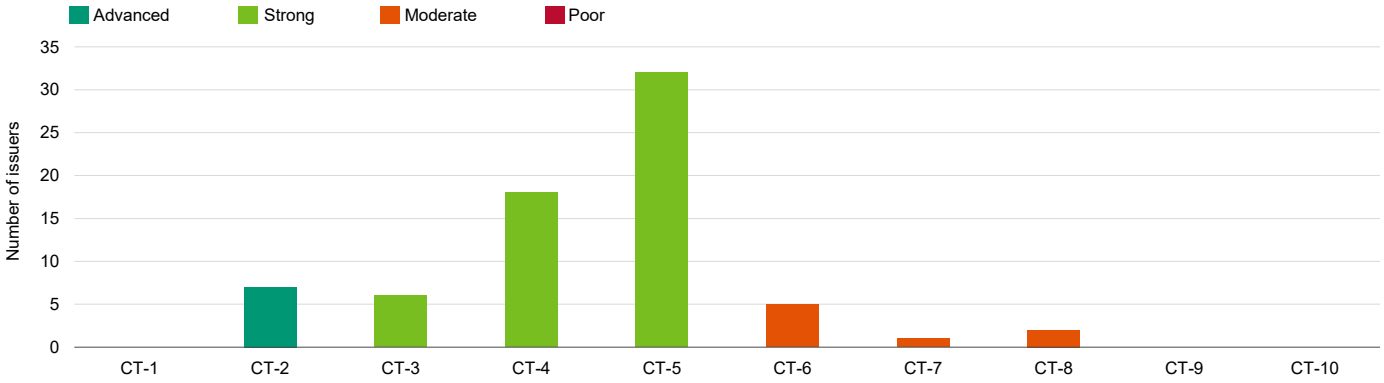
This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

For our entire 71-issuer cohort, which includes issuers that do not own generation assets, the median overall CTA score was also CT-5, indicating strong positioning for the carbon transition (see Exhibit 2). The cohort was primarily comprised of regulated electric and gas utilities and regulated electric networks. Regulated issuers received overall CTA scores indicating advanced to strong positioning, except for DTE, which scored CT-6 in the moderate category. Unregulated issuers' scores had a broader range across advanced, strong and moderate positioning (CT-1 to CT-8).

Exhibit 2

Median overall CTA score of our entire cohort was CT-5

Distribution of overall carbon transition assessment scores for all 71 electric utilities and power generators in our cohort



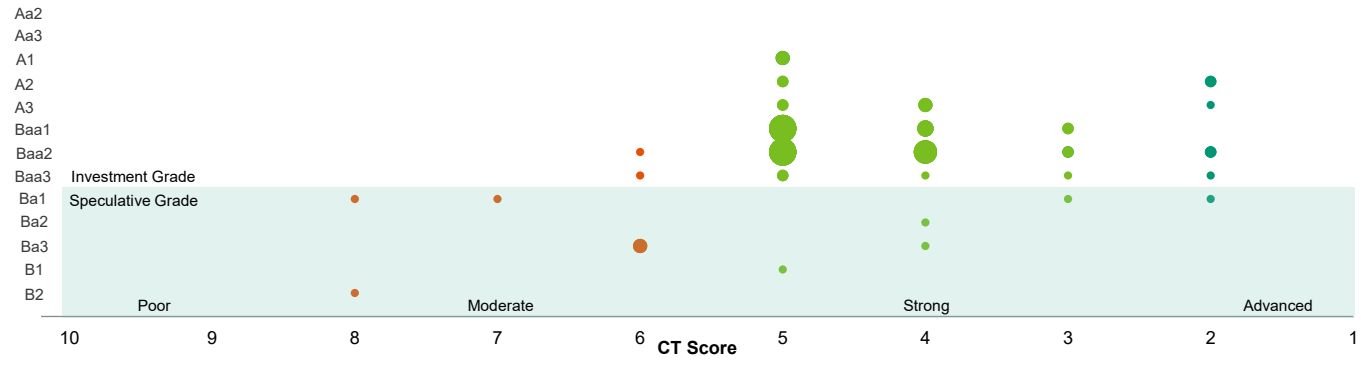
Source: Moody's Investors Service

All issuers that received advanced overall CTA scores have investment-grade ratings, except for NextEra Energy Partners, while all issuers within the moderate band have speculative-grade ratings, except for DTE and Energy Harbor Corp. (Baa3 negative), as shown in Exhibit 3. However, there is no linear relationship between CTA scores and credit ratings because carbon transition risk is just one of many considerations that inform our credit analysis and the weight we place on transition risk will vary by issuer. Companies may improve their creditworthiness if they address carbon transition when it presents a material risk.

Exhibit 3

Most investment-grade issuers in this peer group have strong or advanced positioning for carbon transition

Long-term credit ratings and CTA scores for 71 electric and/or gas utilities and power generators



Source: Moody's Investors Service

This is the third in a series of reports in which we score rated issuers on the basis of their exposure to carbon transition risk (see "Refining and marketing – Global: Location and complexity limit severity of carbon transition risk for most refiners" and "Automotive manufacturing – Global: Substantial variation exists in automakers' carbon transition risk profiles"). We are calculating the scores through the use of our carbon transition assessment (CTA) framework for electric utilities and power generators. We intend to publish CTA scores for utilities and power companies from other regions as well, along with CTA scores of other high risk sectors.

Our report focuses on the ultimate parent companies of US electric utilities and the US operating subsidiaries of foreign parent companies that are rated under Moody's methodologies for regulated electric and gas utilities, regulated electric and gas networks and unregulated utilities and power companies. Although not included in this report, the CTA framework also applies to companies rated under our methodologies for US public power electric utilities, US electric generation and transmission cooperatives and US municipal joint action agencies. The framework does not apply to companies rated under our power generation projects methodology.

How we calculate CTA scores for power generation

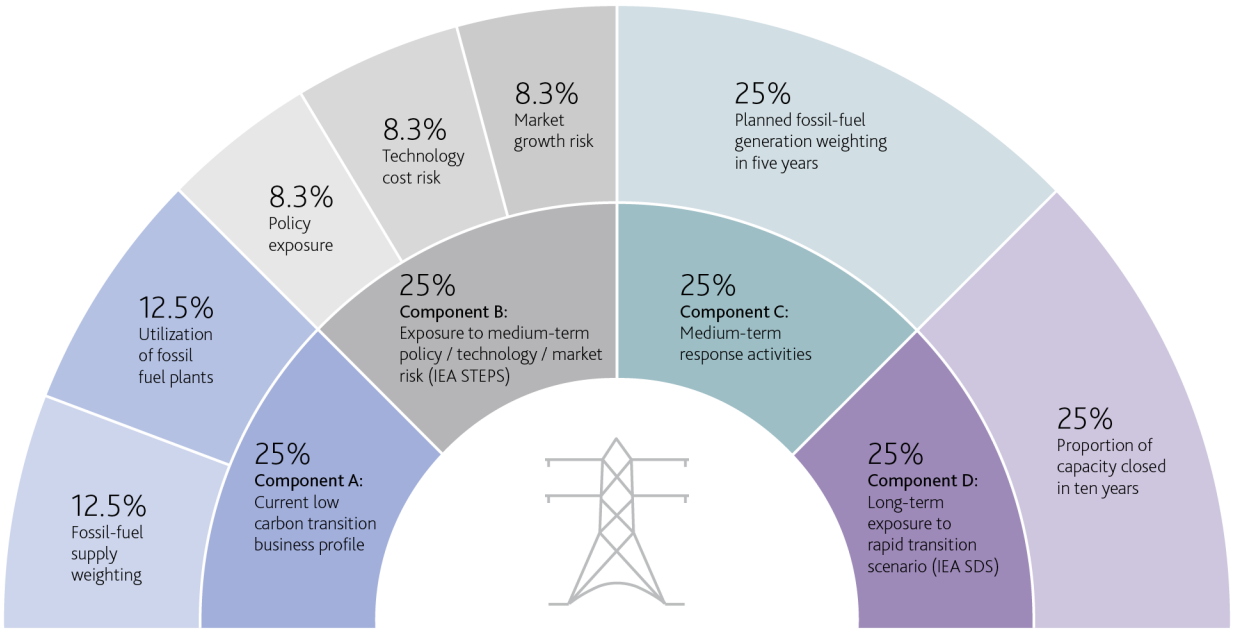
Four, equally weighted components underpin our CTA scores for power generation, as illustrated in Exhibit 4. Component A considers the current business profile of the issuer; Components B and C look at the medium-term risks and opportunities by assessing exposure to technology, market and policy risks and the corporate response to these risks; and Component D considers a company's long-term resilience to a low-carbon transition by looking out over a 10-year horizon.

Our CTA framework for power generation is based on our general CTA framework for non-financial companies (see "Non-financial companies – Global: Framework to assess carbon transition risk for corporate sectors,"), with subcomponents tailored to the power sector.

Exhibit 4

Factors we consider when assessing carbon transition risk for issuers that own generation assets

Components and weightings of our carbon transition assessment framework for power generation

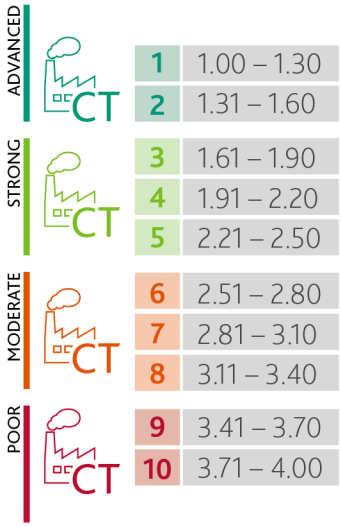


Source: Moody's Investors Service

Our CTA scores are grouped into four categories advanced (dark green), strong (light green), moderate (orange) and poor (red), on a 10-point scale, where the lower the number, the stronger the positioning. Electric utilities and power generators assigned the highest scores, CT-1 and CT-2, exhibit advanced positioning for the carbon transition. They typically have a business model that benefits, rather than faces risks, from the transition to a low-carbon economy. Electric utilities and power generators assigned scores from CT-3 through CT-8 have increasingly greater degrees of exposure to carbon transition risks and are categorized as strong or moderate. Electric utilities and power generators assigned the lowest scores, CT-9 and CT-10, exhibit poor positioning and typically have business models that are fundamentally threatened over the long term by the carbon transition (see Exhibit 5).

Exhibit 5

Summary of our carbon transition assessment (CTA) score categories and descriptions



Issuers exhibit "advanced" positioning for the carbon transition. They typically have a business model that benefits from the transition to a low carbon economy.

Issuers exhibit "strong" positioning for the carbon transition. They either have a business model that is not expected to be materially affected by the carbon transition, or have strategies and plans in place that substantially mitigate their carbon transition exposure.

Issuers exhibit "moderate" positioning for the carbon transition. They have material exposure to carbon transition risks and their relative positioning within this category is determined by variations in their degree of exposure to carbon risks, medium term management actions and long-term resilience.

Issuers exhibit "poor" positioning for the carbon transition. They typically have business models that are fundamentally inconsistent, over the long-term, with the transition to low carbon economy.

Source: Moody's Investors Service

Generation CTA scores by component

Component A - Current low-carbon transition business profile: fossil-fuel plants result in exposure to expected phase out.

The first component of our CTA framework for generation examines a company's current business profile as it pertains to the low-carbon transition. Subcomponents specific to power generation include the proportion of fossil-fuel supply and the utilization rates of coal and combined-cycle gas turbine (CCGT) plants.

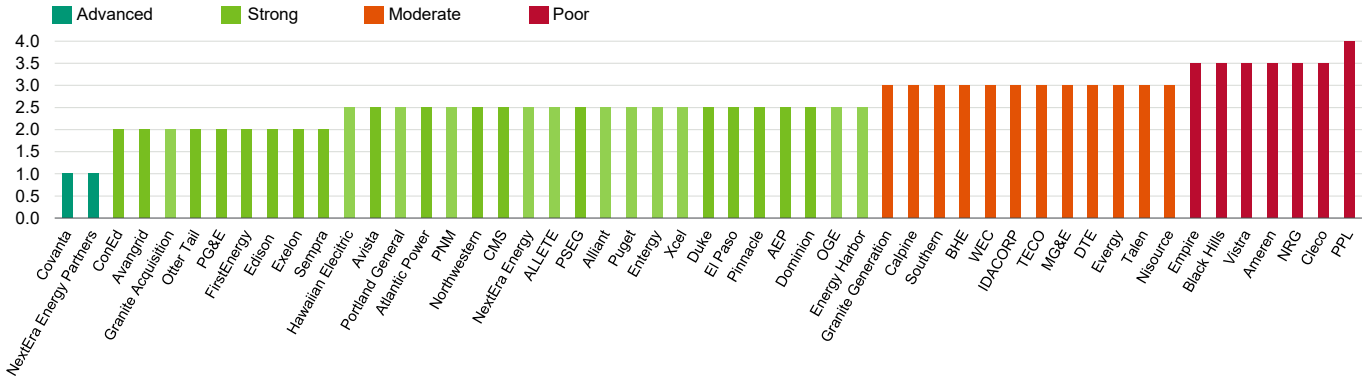
Fossil-fuel supply weighting: Power plants running on fossil fuels still account for the majority of US electricity generation, although the fuel mix has changed over the last decade as coal-fired generation declines. According to the US Energy Information Administration (EIA), 546 coal-fired power units, representing 102 GW of generating capacity were retired in the US between 2010 and 2019. While utilities are rapidly moving away from coal, their generation mix is still heavily comprised of fossil fuels, especially natural gas. The EIA reported that the total electricity generation from fossil fuels decreased from 69% in 2010 to 62.6% in 2019. But during the same period, coal's share of total generation fell to 23.4% from 44.5%, while natural gas-fired plants rose to 38.4% of generation from 23.3%. (see "Electric utilities and power producers – US: Power companies on pace to reduce CO2 emissions").

Issuers like NextEra Energy Partners that generated all of their power from non-fossil-fuel sources during the prior year received a score of 1.0 for advanced positioning (on a scale of 1.0 to 4.0) in this subcomponent (see Exhibit 6). For issuers with fossil-fuel generation, we calculated their score by multiplying the percentage of electricity sales from coal, oil and natural gas by 100, 75 and 50, respectively and scoring this weighted outcome. To receive a strong or advanced score the weighted fossil fuel mix must be below 40 points.

Exhibit 6

The range of power generation mix reflects the shifting fuel mix in the US

Our scoring of CTA subcomponent assessing fossil-fuel supply weighting



Source: Moody's Investors Service

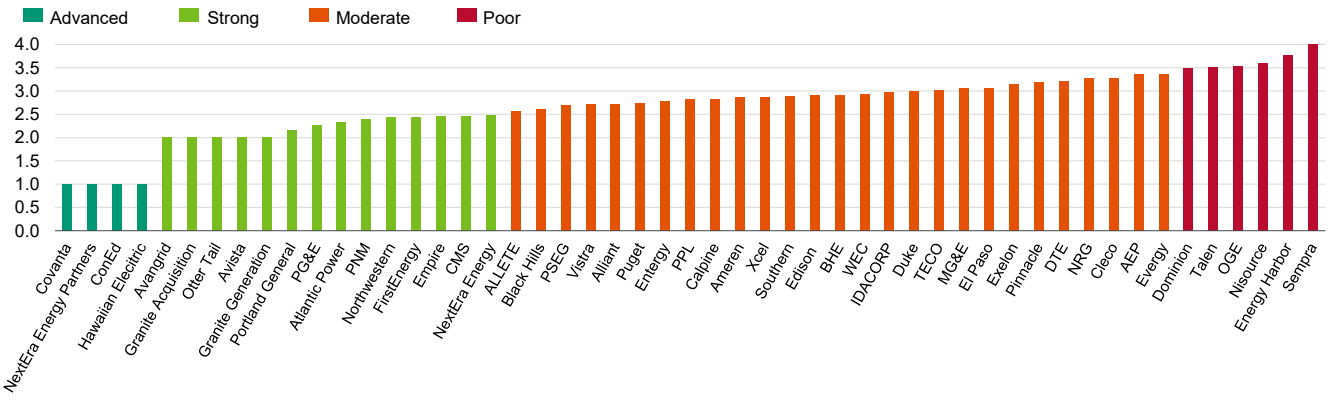
Utilization of fossil-fuel plants: The second subcomponent of Component A assessed the 2019 utilization rate, or capacity factor, of coal and CCGT plants, which were designed to run baseload generation to cover high fixed costs. Low utilization may be an indicator that these plants are a candidate for closure, accelerating asset write-downs, which would be credit negative for the issuer. According to the EIA, the US coal plant capacity factor declined from 64.2% in 2009 to 47.5% in 2019, while the capacity factor of CCGT plants increased from 43.9% to 57.3%, mainly due to low natural gas prices.

In this subcomponent, issuers that do not have any coal or CCGT plants received a score of 1.0 for advanced positioning. A plant would score strongly if the annual capacity factor is above 60% for a coal plant and 50% for a CCGT plant. In 2019, the average utilization of coal and CCGT plants among our scored issuers was 43% and 50%, respectively. Therefore, less than half of the issuers scored strongly for utilization (see Exhibit 7). The high penetration of renewable energy in California explains the low utilization ratio of the two combined cycle natural gas plants of Sempra Energy's (Baa2 stable) utility subsidiary San Diego Gas & Electric Company (Baa1 positive). However, the recent rolling blackouts in the California power market have highlighted the value of these facilities from a systems' reliability perspective.

Exhibit 7

Most issuers exhibited a moderate positioning for coal and CCGT utilization

Our scoring of CTA subcomponent assessing 2019 utilization rate of coal and combined cycle gas turbine (CCGT) plants



Source: Moody's Investors Service

Component B - Medium-term exposure to policy/technology/market risk (IEA STEPS): exposure to policy, technology and market growth risks varies by location

Policy exposure: The first subcomponent of Component B assesses the policy exposure of a power plant based on location, regulatory market framework and type of fuel. In the US, we measured policy risk at the state level because regulatory authority rests primarily

with individual states. Our policy exposure score is composed by the sum of these four elements scores: (1) renewables target; (2) coal support; (3) capacity mechanism and; (4) carbon pricing.

We categorize the US states as being regulated or unregulated based on the regulatory status of the power market. Every coal-fired power plant located in a regulated state received a score for the policy elements of renewables target and coal support, while a coal plant located in an unregulated state also received scores for the policy elements of capacity mechanism and carbon pricing. Other fossil fuel plants received a score for renewables target if located in a regulated state; if located in an unregulated state, they also received a score for capacity mechanism. The sum of a fossil fuel plant policy risk score on these four elements cannot be below 2.0 to ensure the appropriate positioning of fossil fuel plants compared to other technologies.

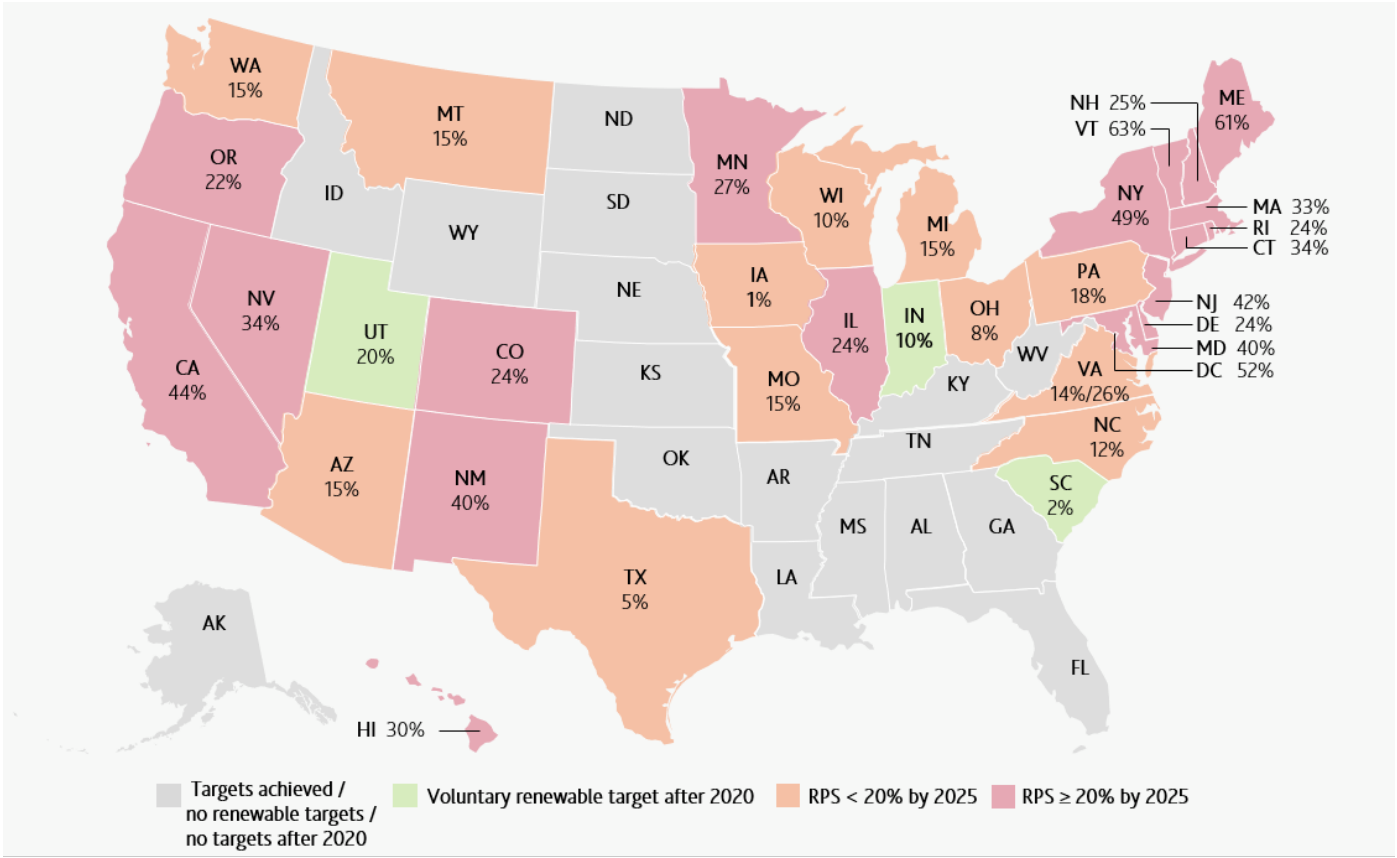
Renewables will receive a score of 1.0 for policy regardless of where the plant is located. As a low-carbon technology, nuclear plants will receive a score of 2.0 for policy risk because they are not exposed to emissions reduction policies. But nuclear plants will not benefit from decarbonization policies to the same degree as renewable energy sources.

In the US, most states adopted a renewable portfolio standard (RPS) requiring a minimum level of the electricity consumption to be generated by renewable resources, increasing the policy risk of fossil-fuel plants located in these states. We used the pro rata 2025 RPS target to score fossil fuel plants, as indicated in Exhibit 8. Fossil-fuel plants did not score well in renewables target portion of the policy exposure score if they are located in states with renewable portfolio standards that require renewable energy sources to account for more than 20% of electricity sales by 2025.

Exhibit 8

Most states have adopted renewable portfolio standards and goals

US state mandates for renewable power as a percentage of applicable retail electricity sales by 2025



Renewable Portfolio Standards (RPS) resource eligibility varies considerably from state to state.

Sources: Berkeley Lab, National Conference of State Legislatures and Moody's Investors Service

We assigned a coal support score of -1 for coal plants located in states of Kentucky, West Virginia and Wyoming because these states have significant coal production activities.

We assigned a score of 0 for fossil-fuel plants located in states with capacity mechanisms, except for plants located in the state of Illinois, because MISO, the independent system operator serving the region, was considered to have a weak capacity mechanism compared to other capacity markets in the US. Fossil-fuel plants located in Illinois received a score of 0.5 for capacity mechanism.

Coal-fired plants located in states participating in the Regional Greenhouse Gas Initiative (RGGI) and/or an emissions cap and trade scheme were assigned a score of 0.5 for carbon pricing element because the average CO2/ton price in 2019 was below our threshold of €20/ton.

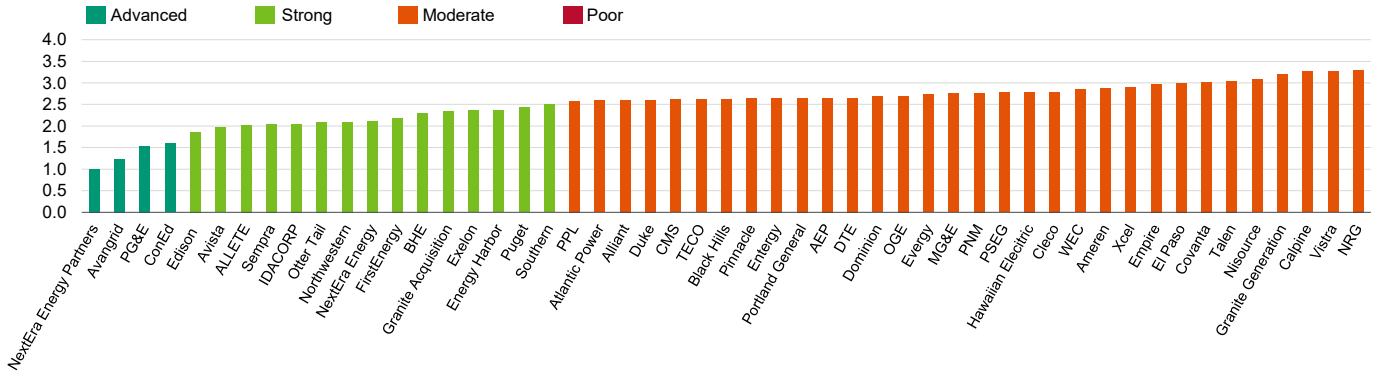
After we scored each fossil-fuel plant under the applicable elements of the policy exposure subcomponent, we combined the scores according to the sector scoring framework.

NextEra Energy Partners, Avangrid, PG&E and Consolidated Edison received a score below 1.6 for advanced positioning because they already derive a significant portion of their generation mix from renewables. As shown in Exhibit 9, most issuers were scored moderate positioning for policy risk. Of these issuers, NRG, Vistra Energy Corp. (Ba1 positive) and Calpine Corporation (Ba3 stable) received the weakest scores because they have a significant portion of their fossil-fuel generation capacity is located in unregulated states with ambitious renewables targets and weaker or no capacity mechanisms. Diversification of generation capacity and the location of these assets prevented any issuers from being scored for poor positioning.

Exhibit 9

Scores vary based on whether states have renewables target, coal support, capacity mechanism or carbon pricing

Our scoring of CTA subcomponent assessing policy risk exposure



Source: Moody's Investors Service

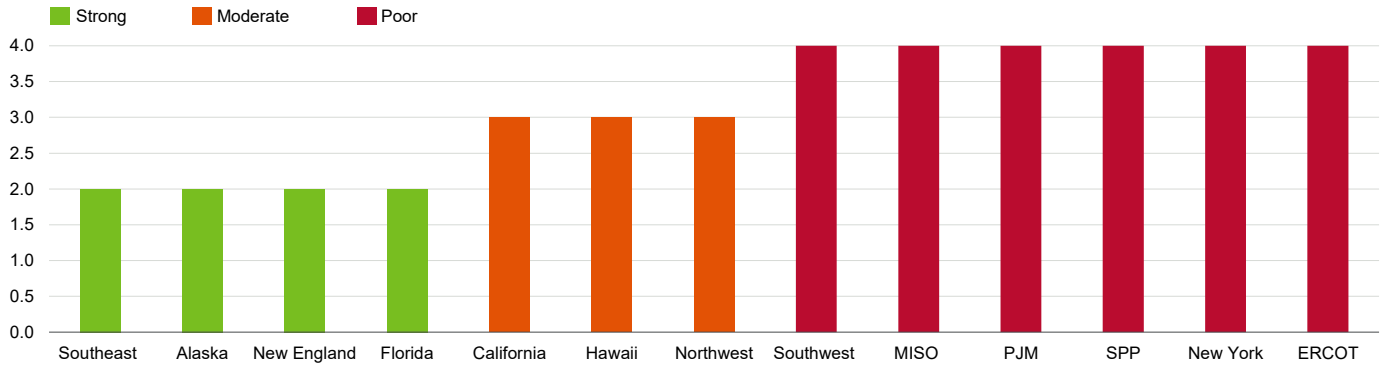
Technology cost risk: This subcomponent scores the existence of lower renewable technology costs in the region where a nonrenewable plant is located relative to other parts of the country. We ranked markets using the cheapest levelized cost of energy (LCOE) for either solar or onshore wind. Recognizing the different ways LCOEs are calculated, for the US we sourced all the LCOEs from Bloomberg New Energy Finance to produce a relative ranking and score them consistently. We recognize the limitations of LCOEs in terms of assumptions, which is why we are using them to score only relative exposure, rather than to calculate actual costs for comparison with existing plants.

Issuers that scored poorly in this subcomponent have fossil-fuel or nuclear capacity within the power regions of Southwest Power Pool, Midcontinent Independent System Operator Inc. (MISO, A1 stable), PJM Interconnection LLC (Aa2 stable), New York and Electric Reliability Council of Texas Inc. (ERCOT, Aa3 stable), where the cost of onshore wind or solar power is low and highly competitive compared to other power regions in the US.

Exhibit 10

Regions with lower renewable costs present greater risk to fossil-fuel and nuclear plants

Score of relative cost of renewables in US regions on a scale of 1 to 4



Sources: Bloomberg New Energy Finance and Moody's Investors Service

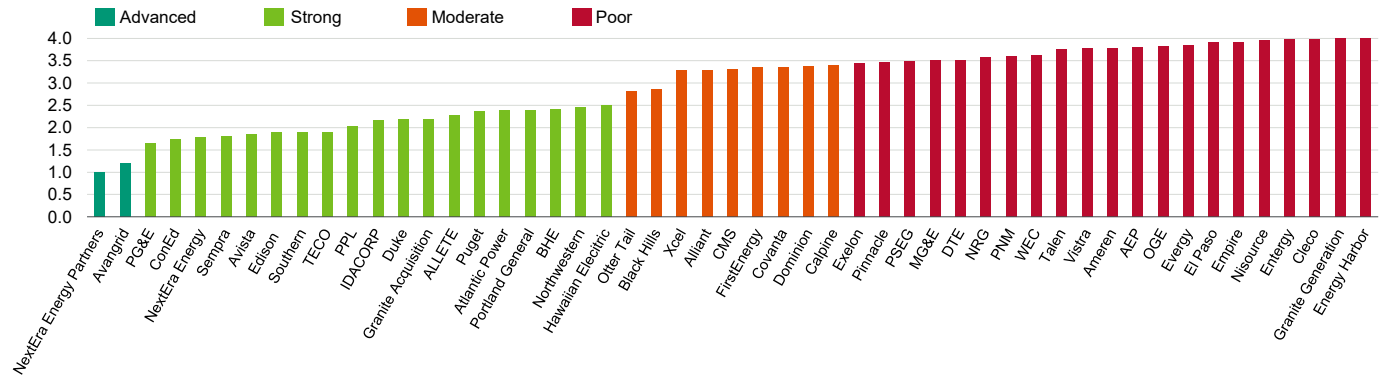
Only renewables plants received the score of 1.0 for advanced positioning. Plants using other fuel types, including nuclear, were scored between 2.0 and 4.0. The higher the cost of renewables technology in the region, the lower the risk for the fossil-fuel plant.

This subcomponent shows a wide range of technology cost risks for issuers in the US. As shown in Exhibit 11, NextEra Energy Partners and Avangrid received scores indicating advanced positioning because they have the highest proportion of renewables generation capacity among the issuers in our cohort, from renewables sources. NiSource Inc. (Baa2 stable), Entergy Corporation (Baa2 stable), Cleco Corporate Holdings LLC (Baa3 stable), Granite Generation LLC (Ba3 stable) and Energy Harbor scored poorly because of the location of their fossil-fuel and nuclear capacity and proportion of each issuer's generation capacity.

Exhibit 11

Poorly scoring issuers have fossil-fuel or nuclear capacity in regions where onshore wind or solar cost is relatively low

Our scoring of CTA subcomponent assessing technology cost risk



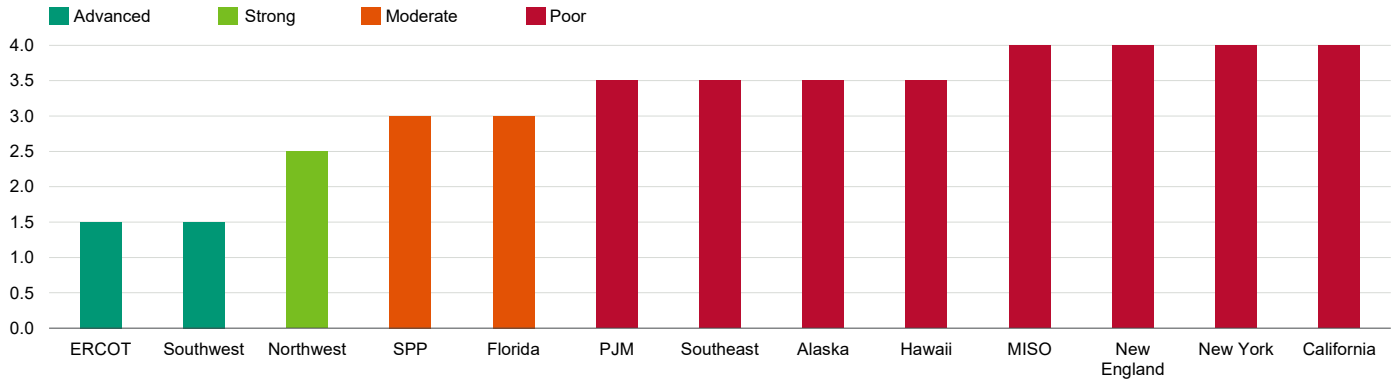
Source: Moody's Investors Service

Market growth risk: This subcomponent score is based on the growth in electricity demand that the North American Electric Reliability Corporation (NERC) forecasts for each of its regions (and subregions, where applicable) for the period 2019-25. The lower the expected growth in electricity demand, the worse the score. Power plants located in markets where NERC expects electricity demand to remain stable or decline are more exposed to energy transition risks because renewable energy will likely displace fossil fuels.

Exhibit 12

Regions where power demand is not increasing are more exposed to transition risk

Score of expected growth in net energy load for the period 2019-25 by region on a scale of 1 to 4



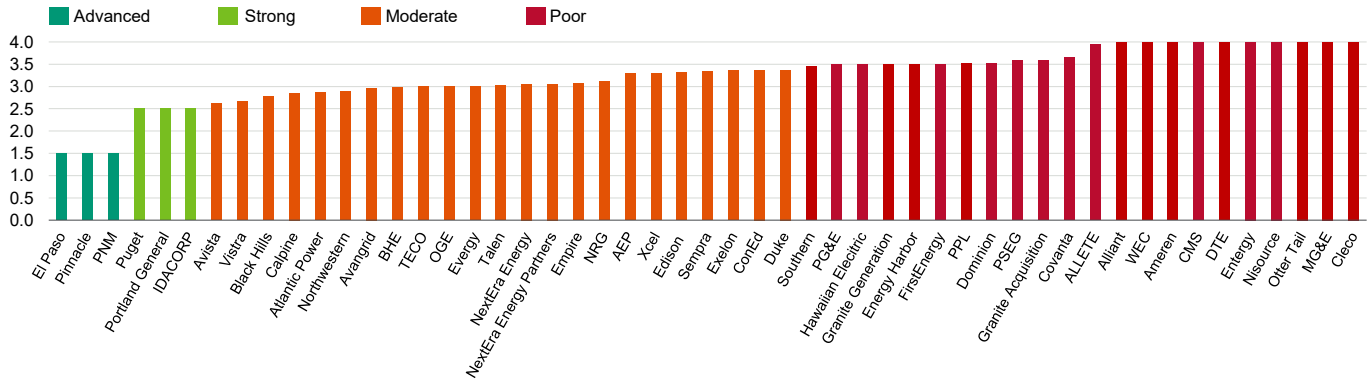
Sources: North American Electric Reliability Corporation and Moody's Investors Service

Most issuers received scores indicating moderate or poor positioning for market growth risk, because the electricity consumption is expected to remain flat or decline in most parts of the country through 2025. Issuers with power plants located in MISO, New England, New York and California scored poorly in this subcomponent. Conversely, issuer with power plants located in ERCOT, Southwest and Northwest scored advanced or strong positioning, as shown in Exhibit 13. El Paso Electric Company (Baa2 stable), Pinnacle West Capital Corporation (A3 negative) and PNM Resources Inc. (Baa3 stable) scored advanced positioning because the majority of their capacity is located in the Southwest where demand for power is growing due to increases in economic and residential development.

Exhibit 13

Most issuers have moderate or poor positioning

Our scoring of CTA subcomponent assessing market growth risk



Source: Moody's Investors Service

Component C - Assessing medium-term response activities: broad range of positioning in terms of expected fossil-fuel supply mix

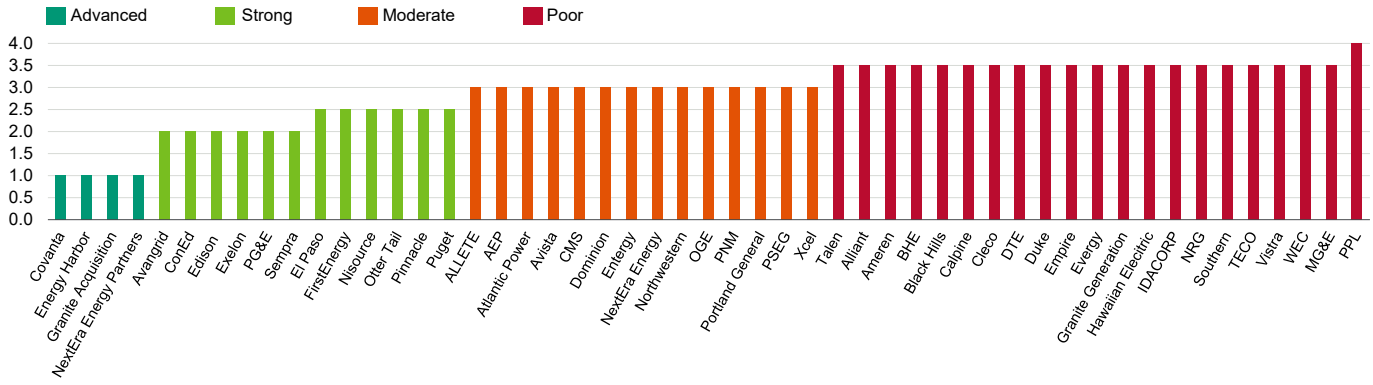
Electric utilities and power generators that are already building renewable capacity and divesting fossil-fuel plants will be better positioned for the low-carbon transition because they do not have to invest as much to align with decarbonisation policies.

Fossil-fuel supply mix in 2025: To assess the medium-term response of issuers, we use just one subcomponent that estimates their fossil-fuel supply mix in 2025, including expected changes to fossil-fuel generating capacity, as well as planned additions of fossil capacity and generation, assuming the total electricity supply in 2025 is the same as 2019 and all retired fossil-fuel capacity and respective generation is replaced by renewables. We did not include specific planned renewable power projects due to the lack of reliable data and the limited visibility of future developments. We scored issuers by dividing its estimated 2025 generation from fossil fuels in MWh by the total electricity sold by the issuer in 2019.

The scoring ranges are tighter than those for the subcomponents of Component A to reflect a more restricted range of future outcomes for fossil-fuel plants. The fossil-fuel supply weighted by respective carbon contents must be below 20 points on a 100-points scale to score strong positioning.

As shown in Exhibit 14, this component reveals a wide degree of variance among the issuers. Covanta, Energy Harbor, Granite Acquisition (B1 stable) and NextEra Energy Partners received scores indicating advanced positioning because their projected fossil fuel supply mix in 2025 is comprised entirely of non-fossil-fuel sources.

Exhibit 14
Wide range of positioning among issuers
Our scoring of CTA subcomponent assessing planned fossil-fuel supply mix in 2025



Source: Moody's Investors Service

Component D - Assessing long-term exposure to rapid transition scenario: significant realignment needed for some issuers

The final component of our CTA framework – long-term exposure to a rapid carbon transition scenario scores the estimated amount of coal-fired capacity retired under the IEA's Sustainable Development Scenario (SDS) until 2030. Under this scenario, global electricity supply moves rapidly toward renewables and other low-carbon sources and coal-fired installed capacity in the US falls by 56%, from 245 GW in 2020 to 108 GW in 2030.

Assuming no growth in electricity consumption, we expect a reduction in US coal-fired generation to around 10% of total power generated in 2030 from 27.5% in 2019. To assess how issuers owning generation assets will fare in this scenario, we consider the proportion of each issuer's generation capacity that will close in 10 years.

Proportion of capacity closed in 10 years (2030): To calculate the score for this subcomponent, we assumed the retirement of all coal plants that either have an announced retirement date by 2030, are located in a state that requires the phaseout of coal generation by 2030 or are owned by an issuer located in a state that requires the phaseout of coal generation by 2030. Then we ranked older coal plants to be retired by age until we reach the cumulative retired capacity determined under IEA SDS. In the US, we assumed that all coal plants which are older than 47 years in 2020 will be retired by 2030.

More than half of the issuers in our cohort scored 2.5 and below for strong and advanced positioning, indicating they have a portfolio of power plants that would be well-positioned under the IEA SDS. Issuers that scored advanced positioning either have no coal capacity or their coal was not retired under our assumptions explained above. As shown in Exhibit 15, Ameren, DTE, Energy Harbor, FirstEnergy, NiSource and Otter Tail Corporation (Baa2 stable) scored 4.0 in this component because they would have to retire more than 30% of their current generation capacity under our assumptions.

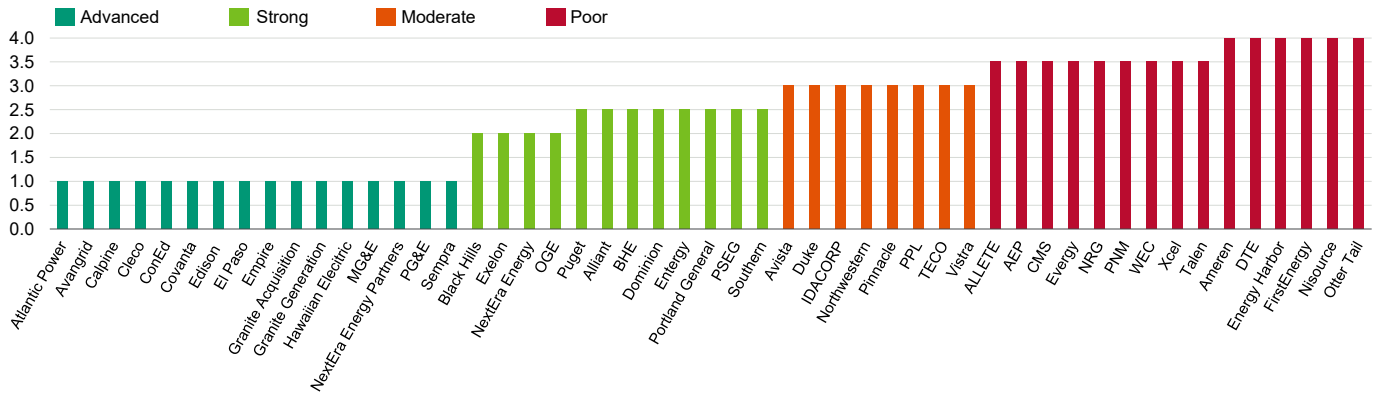
NiSource scored poorly because it plans to retire all of their coal-fired generation by 2028, which represents 72% of their current generation capacity. Otter Tail Power Company (A3 stable), Otter Tail Corporation's principal utility subsidiary, generated 46% of its energy needs from coal in 2019. A significant portion of its coal generation will be retired by 2021 and replaced with renewable and gas-fired generation. As issuers retire coal capacity, their CTA scores will improve accordingly to reflect greater alignment with a low carbon energy transition.

Ameren generates more than 60% of its power from coal and has no immediate plans for diversification. But the US Department of Justice's litigation against the company for alleged violations of the Clean Air Act's New Source Review provisions increases the risk that Ameren may have to accelerate the closure of its coal-fired Rush Island Energy Center or spend significant capital for emissions-control upgrades.

Exhibit 15

More than half of utilities and power companies would be well-positioned for an accelerated transition to a low-carbon economy

Our scoring of CTA subcomponent assessing proportion of capacity closed in 10 years



Source: Moody's Investors Service

Overall CTA scores benefit from reduced carbon exposure of non-generation businesses

Twenty of the 71 issuers in our cohort do not own generation assets and most that do also have distribution, transmission or other related operations. For non-generation activities, we assigned a separate CTA score ranging from 1.0 for low-carbon activities to 4.0 for high-carbon activities, as shown in Exhibit 16. We then weighted each score based on the segment's proportion of the issuer's EBITDA or revenue when EBITDA was not available.

Exhibit 16

CTA scores for non-generation activities of power companies

Specific Business	CTA Score
Other low carbon activities	1.0
Electric transmission / distribution / networks	1.6
Gas transmission / distribution / networks	2.5
Retail	2.5
Other uncategorized*	2.5
Other high carbon activities	4.0

*Other uncategorized refers to business segments where the nature of the business is unclear.
Source: Moody's Investors Service

To calculate each issuer's final, overall CTA score, we combined the CTA scores for their generation and non-generation operations, weighting them based on their proportion of the issuer's EBITDA. NextEra Energy Partners was the only issuer to receive both generation CTA and overall CTA scores indicating advanced positioning. While Covanta received generation CTA scores indicating advanced positioning, they received slightly lower overall CTA scores, indicating strong positioning because of the proportion of EBITDA from their waste businesses, which received a score of 2.5 for carbon transition risk. By contrast, the overall CTA scores of Ameren and PPL each improved by five notches from their generation CTA scores because they derive a significant proportion of their EBITDA from businesses with lower transition risk, predominantly electric transmission and distribution.

Non-generation issuers scoring the best were those focused on electric transmission and distribution, such as American Transmission Company LLC (A2 stable), Central Hudson Gas & Electric Corporation (A3 negative), Duquesne Light Holdings Inc. (Baa3 stable), Electric Transmission Texas LLC (Baa2 stable), Transource Energy LLC (A2 stable) and ITC Holdings Corp. (Baa2 stable).

Filed: 2021-04-19, EB-2020-0290
Exhibit L-C1-01-Staff-055
Attachment 1, Page 13 of 18

Appendix

Exhibit 17

Carbon transition assessment (CTA) scores for the power generation operations of the 51 issuers in our cohort that own generation assets

				Component A: Current Profile			Component B: Medium-term exposure to technology /market/policy risk				Component C: Medium-term response activities		Component D: Long-term exposure to rapid transition scenario	
				Fossil-fuel supply weighting	Utilization of fossil fuel plants		Policy exposure	Technology cost risk	Market growth risk		Planned fossil-fuel generation weighting in 5 years		Proportion of capacity closed in 10 years	
Issuer	LT Rating	Generation CTA	Score	Score	Score	Component A	Score	Score	Score	Component B	Score	Component C	Score	Component D
NextEra Energy Partners, LP	Ba1	CT-1	1.17	1.00	1.00	1.00	1.00	1.00	3.06	1.69	1.00	1.00	1.00	1.00
Covanta Holding Corporation	Ba3	CT-2	1.59	1.00	1.00	1.00	3.02	3.36	3.65	3.35	1.00	1.00	1.00	1.00
Consolidated Edison, Inc.	Baa2	CT-3	1.68	2.00	1.00	1.50	1.60	1.75	3.37	2.24	2.00	2.00	1.00	1.00
Granite Acquisition, Inc.	B1	CT-3	1.68	2.00	2.00	2.00	2.35	2.19	3.58	2.71	1.00	1.00	1.00	1.00
Avangrid, Inc.	Baa1	CT-3	1.70	2.00	2.00	2.00	1.23	1.19	2.97	1.79	2.00	2.00	1.00	1.00
PG&E Corporation	Ba2	CT-3	1.84	2.00	2.26	2.13	1.54	1.65	3.50	2.23	2.00	2.00	1.00	1.00
Edison International	Baa3	CT-4	1.95	2.00	2.92	2.46	1.86	1.88	3.31	2.35	2.00	2.00	1.00	1.00
Sempra Energy	Baa2	CT-4	2.10	2.00	4.00	3.00	2.05	1.81	3.34	2.40	2.00	2.00	1.00	1.00
Atlantic Power Corporation	Ba3	CT-5	2.26	2.50	2.34	2.42	2.59	2.40	2.86	2.61	3.00	3.00	1.00	1.00
El Paso Electric Company	Baa2	CT-5	2.27	2.50	3.06	2.78	3.00	3.91	1.50	2.81	2.50	2.50	1.00	1.00
Hawaiian Electric Company, Inc.	Baa2	CT-5	2.29	2.50	1.00	1.75	2.79	2.49	3.50	2.93	3.50	3.50	1.00	1.00
Exelon Corporation	Baa2	CT-5	2.41	2.00	3.14	2.57	2.36	3.45	3.36	3.05	2.00	2.00	2.00	2.00
NextEra Energy, Inc.	Baa1	CT-5	2.45	2.50	2.48	2.49	2.12	1.79	3.06	2.32	3.00	3.00	2.00	2.00
Puget Energy, Inc.	Baa3	CT-6	2.51	2.50	2.74	2.62	2.43	2.36	2.50	2.43	2.50	2.50	2.50	2.50
Portland General Electric Company	A3	CT-6	2.59	2.50	2.17	2.33	2.65	2.40	2.50	2.52	3.00	3.00	2.50	2.50
Avista Corp.	Baa2	CT-6	2.60	2.50	2.00	2.25	1.97	1.86	2.61	2.15	3.00	3.00	3.00	3.00
Granite Generation, LLC	Ba3	CT-6	2.64	3.00	2.00	2.50	3.20	4.00	3.50	3.57	3.50	3.50	1.00	1.00
Calpine Corporation	Ba3	CT-6	2.65	3.00	2.82	2.91	3.27	3.39	2.86	3.17	3.50	3.50	1.00	1.00
Empire District Electric Company (The)	Baa1	CT-6	2.70	3.50	2.46	2.98	2.98	3.92	3.07	3.33	3.50	3.50	1.00	1.00
Pinnacle West Capital Corporation	A3	CT-6	2.72	2.50	3.19	2.85	2.64	3.46	1.50	2.54	2.50	2.50	3.00	3.00
Northwestern Corporation	Baa2	CT-6	2.74	2.50	2.43	2.47	2.10	2.45	2.89	2.48	3.00	3.00	3.00	3.00
Madison Gas and Electric Company	A1	CT-6	2.74	3.00	3.06	3.03	2.75	3.50	4.00	3.42	3.50	3.50	1.00	1.00
OGE Energy Corp.	Baa1	CT-6	2.80	2.50	3.53	3.02	2.69	3.82	3.00	3.17	3.00	3.00	2.00	2.00
Black Hills Corporation	Baa2	CT-7	2.83	3.50	2.60	3.05	2.63	2.87	2.77	2.76	3.50	3.50	2.00	2.00
Public Service Enterprise Group Incorporated	Baa1	CT-7	2.84	2.50	2.70	2.60	2.77	3.48	3.58	3.28	3.00	3.00	2.50	2.50
Energy Harbor Corp.	Baa3	CT-7	2.86	2.50	3.78	3.14	2.36	4.00	3.50	3.29	1.00	1.00	4.00	4.00
Cleco Corporate Holdings LLC	Baa3	CT-7	2.87	3.50	3.27	3.39	2.79	3.99	4.00	3.60	3.50	3.50	1.00	1.00
Otter Tail Corporation	Baa2	CT-7	2.87	2.00	2.00	2.00	2.09	2.82	4.00	2.97	2.50	2.50	4.00	4.00
Berkshire Hathaway Energy Company	A3	CT-7	2.88	3.00	2.92	2.96	2.30	2.40	2.98	2.56	3.50	3.50	2.50	2.50
PNM Resources, Inc.	Baa3	CT-7	2.89	2.50	2.39	2.44	2.76	3.61	1.50	2.62	3.00	3.00	3.50	3.50
Southern Company (The)	Baa2	CT-7	2.89	3.00	2.88	2.94	2.50	1.88	3.45	2.61	3.50	3.50	2.50	2.50
Dominion Energy, Inc.	Baa2	CT-7	2.92	2.50	3.48	2.99	2.69	3.37	3.52	3.19	3.00	3.00	2.50	2.50
Entergy Corporation	Baa2	CT-7	2.92	2.50	2.79	2.64	2.65	3.98	4.00	3.54	3.00	3.00	2.50	2.50
FirstEnergy Corp.	Ba1	CT-7	2.93	2.00	2.44	2.22	2.18	3.36	3.50	3.01	2.50	2.50	4.00	4.00
IDACORP, Inc.	Baa1	CT-7	2.93	3.00	2.98	2.99	2.05	2.17	2.50	2.24	3.50	3.50	3.00	3.00
ALLETE, Inc.	Baa1	CT-7	2.95	2.50	2.57	2.53	2.02	2.28	3.94	2.75	3.00	3.00	3.50	3.50
Alliant Energy Corporation	Baa2	CT-7	2.98	2.50	2.73	2.61	2.61	3.29	3.98	3.29	3.50	3.50	2.50	2.50
Duke Energy Corporation	Baa1	CT-7	2.99	2.50	3.01	2.75	2.61	2.18	3.37	2.72	3.50	3.50	3.00	3.00
TECO Energy, Inc.	Baa2	CT-7	3.00	3.00	3.02	3.01	2.61	1.90	3.00	2.50	3.50	3.50	3.00	3.00
CMS Energy Corporation	Baa1	CT-7	3.07	2.50	2.47	2.48	2.61	3.30	3.99	3.30	3.00	3.00	3.50	3.50
Xcel Energy Inc.	Baa1	CT-7	3.09	2.50	2.88	2.69	2.90	3.29	3.29	3.16	3.00	3.00	3.50	3.50
American Electric Power Company, Inc.	Baa2	CT-8	3.17	2.50	3.35	2.93	2.65	3.80	3.29	3.25	3.00	3.00	3.50	3.50
Vistra Energy Corp.	Ba1	CT-8	3.21	3.50	2.72	3.11	3.27	3.77	2.66	3.23	3.50	3.50	3.00	3.00
PPL Corporation	Baa2	CT-8	3.28	4.00	2.82	3.41	2.58	2.02	3.51	2.71	4.00	4.00	3.00	3.00
Evergy, Inc.	Baa2	CT-8	3.34	3.00	3.37	3.18	2.73	3.84	3.00	3.19	3.50	3.50	3.50	3.50
WEC Energy Group, Inc.	Baa1	CT-8	3.36	3.00	2.92	2.96	2.85	3.63	3.99	3.49	3.50	3.50	3.50	3.50
NiSource Inc.	Baa2	CT-8	3.37	3.00	3.60	3.30	3.08	3.97	4.00	3.68	2.50	2.50	4.00	4.00
Talen Energy Supply, LLC	B2	CT-8	3.38	3.00	3.51	3.25	3.04	3.76	3.03	3.28	3.50	3.50	3.50	3.50
NRG Energy, Inc.	Ba1	CT-9	3.43	3.50	3.27	3.39	3.30	3.58	3.11	3.33	3.50	3.50	3.50	3.50
DTE Energy Company	Baa2	CT-9	3.50	3.00	3.20	3.10	2.66	3.52	3.99	3.39	3.50	3.50	4.00	4.00
Ameren Corporation	Baa1	CT-9	3.56	3.50	2.87	3.18	2.89	3.78	3.99	3.55	3.50	3.50	4.00	4.00

Score legend

Advanced Strong Moderate Poor

Component/subcomponent scores are based on a four-point scale. The overall score, which is the sum of the four, equally weighted component scores, is then mapped to the 10-point CTA scale. The four categories of positioning (advanced, strong, moderate, poor), which are defined in Exhibit 5, are color-coded and are applied in the scoring of each subcomponent, component and overall CTA score.

Source: Moody's Investors Service

Exhibit 18

Carbon transition assessment (CTA) scores for the 71 issuers in our cohort

Issuer	LT Rating	Overall CTA score	Score	Generation CTA score	Score
NextEra Energy Partners, LP	Ba1	CT-2	1.50	CT-1	1.17
American Transmission Company LLC	A2	CT-2	1.60	-	-
Central Hudson Gas & Electric Corporation	A3	CT-2	1.60	-	-
Duquesne Light Holdings, Inc.	Baa3	CT-2	1.60	-	-
Electric Transmission Texas, LLC	Baa2	CT-2	1.60	-	-
Transource Energy, LLC	A2	CT-2	1.60	-	-
ITC Holdings Corp.	Baa2	CT-2	1.60	-	-
FirstEnergy Corp.	Ba1	CT-3	1.68	CT-7	2.93
PPL Corporation	Baa2	CT-3	1.70	CT-8	3.28
Eversource Energy	Baa1	CT-3	1.73	-	-
Avangrid, Inc.	Baa1	CT-3	1.78	CT-3	1.70
Edison International	Baa3	CT-3	1.78	CT-4	1.95
Consolidated Edison, Inc.	Baa2	CT-3	1.82	CT-3	1.68
El Paso Electric Company	Baa2	CT-4	1.94	CT-5	2.27
Hawaiian Electric Company, Inc.	Baa2	CT-4	1.95	CT-5	2.29
CenterPoint Energy, Inc.	Baa2	CT-4	1.98	-	-
PG&E Corporation	Ba2	CT-4	2.01	CT-3	1.84
Public Service Enterprise Group Incorporated	Baa1	CT-4	2.02	CT-7	2.84
Exelon Corporation	Baa2	CT-4	2.05	CT-5	2.41
UNS Electric, Inc.	A3	CT-4	2.05	-	-
Puget Energy, Inc.	Baa3	CT-4	2.06	CT-6	2.51
Sempra Energy	Baa2	CT-4	2.06	CT-4	2.10
American Electric Power Company, Inc.	Baa2	CT-4	2.08	CT-8	3.17
NextEra Energy, Inc.	Baa1	CT-4	2.08	CT-5	2.45
Covanta Holding Corporation	Ba3	CT-4	2.09	CT-2	1.59
Unitil Corporation	Baa2	CT-4	2.09	-	-
Avista Corp.	Baa2	CT-4	2.10	CT-6	2.60
Portland General Electric Company	A3	CT-4	2.10	CT-6	2.59
Pinnacle West Capital Corporation	A3	CT-4	2.16	CT-6	2.72
Ameren Corporation	Baa1	CT-4	2.18	CT-9	3.56
OGE Energy Corp.	Baa1	CT-4	2.20	CT-6	2.80
Berkshire Hathaway Energy Company	A3	CT-5	2.21	CT-7	2.88
Northwestern Corporation	Baa2	CT-5	2.23	CT-6	2.74
Granite Acquisition, Inc.	B1	CT-5	2.25	CT-3	1.68
PNM Resources, Inc.	Baa3	CT-5	2.25	CT-7	2.89
Empire District Electric Company (The)	Baa1	CT-5	2.26	CT-6	2.70
IDACORP, Inc.	Baa1	CT-5	2.27	CT-7	2.93
Alliant Energy Corporation	Baa2	CT-5	2.31	CT-7	2.98
Madison Gas and Electric Company	A1	CT-5	2.31	CT-6	2.74
Otter Tail Corporation	Baa2	CT-5	2.32	CT-7	2.87
Southern Company (The)	Baa2	CT-5	2.33	CT-7	2.89
Duke Energy Corporation	Baa1	CT-5	2.34	CT-7	2.99
TECO Energy, Inc.	Baa2	CT-5	2.35	CT-7	3.00
Cleco Corporate Holdings LLC	Baa3	CT-5	2.37	CT-7	2.87
Xcel Energy Inc.	Baa1	CT-5	2.37	CT-7	3.09
Dominion Energy, Inc.	Baa2	CT-5	2.38	CT-7	2.92
Entergy Corporation	Baa2	CT-5	2.38	CT-7	2.92
WEC Energy Group, Inc.	Baa1	CT-5	2.39	CT-8	3.36
CMS Energy Corporation	Baa1	CT-5	2.41	CT-7	3.07
UGI Utilities, Inc.	A2	CT-5	2.45	-	-
Black Hills Corporation	Baa2	CT-5	2.47	CT-7	2.83
Evergy, Inc.	Baa2	CT-5	2.47	CT-8	3.34

Issuer	LT Rating	Overall CTA score	Score	Generation CTA score	Score
ALLETE, Inc.	Baa1	CT-5	2.48	CT-7	2.95
NiSource Inc.	Baa2	CT-5	2.49	CT-8	3.37
Atmos Energy Corporation	A1	CT-5	2.50	-	-
New Jersey Natural Gas Company	A1	CT-5	2.50	-	-
Northwest Natural Gas Company	Baa1	CT-5	2.50	-	-
ONE Gas, Inc	A2	CT-5	2.50	-	-
SEMCO Energy, Inc.	Baa1	CT-5	2.50	-	-
South Jersey Gas Company	A3	CT-5	2.50	-	-
Southwest Gas Holdings, Inc.	Baa1	CT-5	2.50	-	-
Spire Inc.	Baa2	CT-5	2.50	-	-
WGL Holdings, Inc.	Baa1	CT-5	2.50	-	-
DTE Energy Company	Baa2	CT-6	2.53	CT-9	3.50
Atlantic Power Corporation	Ba3	CT-6	2.55	CT-5	2.26
Calpine Corporation	Ba3	CT-6	2.63	CT-6	2.65
Granite Generation, LLC	Ba3	CT-6	2.64	CT-6	2.64
Energy Harbor Corp.	Baa3	CT-6	2.80	CT-7	2.86
NRG Energy, Inc.	Ba1	CT-7	3.08	CT-9	3.43
Vistra Energy Corp.	Ba1	CT-8	3.13	CT-8	3.21
Talen Energy Supply, LLC	B2	CT-8	3.38	CT-8	3.38

Score legend

Advanced Strong Moderate Poor

The four categories of positioning (advanced, strong, moderate, poor), which are defined in Exhibit 4, are color-coded and are applied in the scoring of the overall and generation CTA scores.

Source: Moody's Investors Service

Moody's related publications

Assessment Frameworks and scoring reports

» Electric Utilities and Power Generators - Global Carbon transition assessment framework for electric utilities and power, 3 November 2020

» Refining and marketing – Global: Location and complexity limit severity of carbon transition risk for most refiners, 21 September 2020

» Refining and Marketing – Global: Carbon transition assessment framework for refining and marketing companies, 10 July 2020

» Automotive manufacturing – Global: Substantial variation exists in automakers' carbon transition risk profiles, 4 November 2019

» Automotive manufacturing – Global: Carbon transition assessment framework for auto manufacturers, 24 September 2019

» Non-financial companies – Global Framework to assess carbon transition risk for corporate sectors, 24 September 2019

Sector In-Depth

» Power Generation – US: State policies drive long-term US renewable energy demand, 22 September 2020

» Electric Utilities and Power Companies – US: Nuclear operators face growing climate risk but resiliency investments mitigate impact, 18 August 2020

» ESG – Global: Climate scenarios vital to assess credit impact of carbon transition, physical risks, 10 March 2020

» Regulated electric and gas utilities – US: Grid hardening, regulatory support key to credit quality as climate hazards worsen, 2 March 2020

» Regulated electric utilities – US: Intensifying climate hazards to heighten focus on infrastructure investments, 16 January 2020

» Cross-Sector – Europe: EU decarbonisation strategy accelerating energy transition, 19 November 2019

» Electric utilities and power producers – US: Power companies on pace to reduce CO2 emissions, 26 September 2019

» Power generation – US: Nuclear zero emission credits reduce carbon transition risk but change market dynamics, 27 June 2019

» Power generation – US: FAQ on the economics of renewable energy, battery storage and fossil-fuel power plants, 12 June 2019

» Cross-Sector - Global Frequently asked investor questions about environmental, social and governance issues, 5 March 2019

» Environmental Risks – Global: Heat map: 11 sectors with $2.2 trillion debt have elevated environmental risk exposure, 25 September 2018

Cross-Sector Rating Methodology

» General Principles for Assessing Environmental, Social and Governance Risks: Proposed Methodology Update, 23 September 2020

» General Principles for Assessing Environmental, Social and Governance Risks, 9 January 2019

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Attachment 1, Page 18 of 18

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Board Staff Interrogatory #56

Interrogatory

Reference:
Exhibit C1 / Tab 1/ Schedule 1 / Attachment 1 / p. 11

Preamble:

On page 11 of the Concentric Report, Concentric stated:

> The OEB [in EB-2007-0905] 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.

Question(s):

a) In typical Canadian project finance transactions related to zero emitting resources with long term power purchase agreements (PPAs), what level of equity thickness is normally required to obtain financing?

b) How would Concentric compare the level of risk associated with a long term PPA between a zero emitting resource and a Canadian provincially backed offtaker with the level of risk that OPG faces in its regulatory arrangements with the OEB?

Response

Response prepared by Concentric Energy Advisors

a) Concentric is not aware of whether there is (i) a "typical" Canadian project finance transaction as described in the interrogatory, or (ii) what level of equity thickness is "normally required." Rather, Concentric expects that the capital structure for any given project finance project is driven by the availability and cost of debt financing, which is further driven by the stability and security of the project's cash flows. The structures and risk allocation in these transactions are very different than those of regulated utilities.

b) In responding to this interrogatory, Concentric has interpreted "its regulatory arrangements with the OEB" to refer to OPG's regulatory framework. Concentric does not consider a PPA between a zero emitting resource and a Canadian provincially backed off-taker to be sufficiently comparable to OPG's regulatory framework from a risk perspective.

Board Staff Interrogatory #57

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 73

Preamble:

On page 73 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) If a holding company's unregulated assets are at least as risky as its regulated assets, but the holding company equity ratio is less than the authorized equity ratio, does that imply that the capital markets would be comfortable with a lower authorized equity ratio? Please explain with reasons.

Response

Response prepared by Concentric Energy Advisors

In this hypothetical scenario, Concentric assumes the holding company has a lower equity ratio than its operating utility company's authorized equity ratio. Concentric would not interpret this scenario as indicating "the capital markets would be comfortable with a lower authorized equity ratio." There are many factors that can impact the capital structure at a holding company, and the holding company's capital structure does not necessarily correspond to that of the operating utility, especially over shorter time periods, and including consideration of the effect of structured subordination. In addition, sometimes, a holding company may incur addition debt to finance its regulated and unregulated businesses. Further, the risks, financing needs, and cost of borrowing of a holding company and an operating utility can be different.

Board Staff Interrogatory #58

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 30, 35

Preamble:

On page 30 of the Concentric Report, Concentric stated:

> … 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 [first of a kind] 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.

On page 35 of the Concentric Report, Concentric stated:

> …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.

Question(s):

a) Upon completion, what is the total expected cost of the additional two units at Southern Co.'s Vogtle site?

b) Are the differences in execution risk (i.e. cost, scope and timing) in OPG's current nuclear refurbishment program from prior such programs as large as the differences between the construction of new Westinghouse AP1000 units and maintenance of the existing units at Southern Co.'s Vogtle site in Georgia?

Response

Response prepared by Concentric Energy Advisors

a) A July 2020 article from Reuters indicated that the total expected cost of Vogtle Units 3 and 4 was over $25 billion. Georgia Power has a 45.7% ownership interest in Vogtle. Georgia Power's capital cost for construction is forecast at $8.4 billion and financing costs are projected to be $3.0 billion, for a total cost of $11.4 billion (i.e., 45.7% times $25 billion).

b) The question appears to ask for a comparison of the execution risk associated with OPG's current DRP to prior refurbishment programs at OPG, and whether that risk is as large as the difference between the construction of new Vogtle units as compared to the maintenance of existing Vogtle units. While the risks of nuclear refurbishment are different than those of construction, Concentric's view is that those risks are no smaller in scope or magnitude. As discussed in Concentric's report on page 40, prior CANDU refurbishments and large nuclear construction projects in the U.S. have encountered significant challenges. Additionally, the magnitude of capital investment for OPG in the DRP project exceeds that of Georgia Power in the Vogtle project.

Board Staff Interrogatory #59

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 38

Preamble:

On page 38 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Concentric focused on digital turbine controls and generator excitation controls as being among the new technologies to be deployed during OPG's current refurbishment program. Are either of these technologies unique to nuclear power plants?

b) Has OPG installed digital controls at any of its hydroelectric generating stations? If yes, how did actual budget and schedule compare with the planned budget and schedule for such installations, and has the performance of the digital controls met expectations prior to installation?

Response

a) Digital turbine controls and excitation controls are not unique to nuclear plants; however, there are material differences between the turbine controls of nuclear plants, thermal (non-nuclear, peaking) units, and hydroelectric plants.

Nuclear plants are almost invariably base load units. Digital control systems on base load steam turbine generators tend to be more complex than those on peaking (thermal) units. Base load steam turbine controls have more redundancy and logic to prevent spurious trips due to instrumentation failure and/or false signals. This need is driven by longer run times between maintenance and higher financial losses for base load unit trips. Hydroelectric generating stations do not have analogous

systems. Hydroelectric turbine controls are much simpler than those used for nuclear power plants or other base load steam turbine plants.

b) Digital control systems have been implemented to varying degrees at OPG's thermal stations, often replacing a portion, but not all, of the original control systems. For example, at the Lennox Generating Station, the unit control computers, turbovisory instrumentation and exciters have been upgraded, but the original mechanical governors have been retained. The performance of the controls met expectations but in some cases had some initial issues. Some probes did not perform as expected and had to be reconfigured. Readings were also now more accurate and had to be interpreted compared to past instrumentation that was less accurate to confirm acceptability and operating range. The turbovisory system at the Lennox station was installed on budget.

OPG has installed digital turbine controls at some of its hydroelectric generating stations. OPG's hydroelectric digital turbine control installation experiences range from approximately 4% over budget to 17% below budget. OPG's hydroelectric digital turbine control installations range from over schedule (excess of a year) to on schedule. The performance of digital turbine controls has ranged from operating reliably to having minor maintenance issues.

OPG has installed digital generator excitation controls in most of its hydroelectric generating stations. Installation of digital generator excitation controls at hydroelectric generating stations is routine, typically goes according to plan, and performance meets expectations.

Board Staff Interrogatory #60

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 39-40

Preamble:

On pages 39-40 of the Concentric Report, Concentric discussed the current COVID-19 pandemic, and its impact as a "black swan event" on OPG's operations. On page 40 of the Concentric Report, Concentric stated:

> Depending on the course of the COVID-19 pandemic, these factors [productivity risk and resource availability risk] may have an impact on the ultimate cost and schedule of the DRP.

Question(s):

a) Why does Concentric believe that the COVID-19 pandemic is a risk for the 2022-2026 period, as opposed to a temporary risk ending by December 31, 2021?

Response

Response prepared by Concentric Energy Advisors

The scope, impact, and duration of the COVID-19 pandemic is currently unknown and there is no basis to conclude that the risk terminates on December 31, 2021. As discussed on pages 39-40 of Concentric's Report, COVID-19 presents an ongoing risk for large construction projects such as OPG's DRP because the pandemic has limited and is likely to continue to limit the supply of materials and labor for large scale projects. This can result in project delays and cost overruns. As an example, Georgia Power announced that it recorded a charge against Q2 2020 pre-tax income of $149 million due to possible cost increases related to COVID-19. Furthermore, according to a January 13, 2021 article published by S&P Global Market Intelligence (Attachment 1), COVID-19 has created more uncertainty regarding whether Vogtle Units 3 and 4 will be completed according to the current project schedule. OPG has noted that the COVID-19 pandemic is estimated to have resulted in and increase in DRP costs of $150 million. The impact of COVID-19 on the DRP project is discussed in greater detail at Ex. L-A2-2-Staff-018.

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-Staff-60
Attachment 1
Page 1 of 2

Wall Street braces for further delays, cost overruns at Vogtle nuke project

Wednesday, January 13, 2021 11:15 AM ET

By Darren Sweeney

Craftsmen work near the Alvin W. Vogtle nuclear plant's partially-built Unit 3 in August 2018.
Source: Georgia Power Co.

Wall Street is growing wary of Southern Co.'s promise to meet the regulatory approved in-service dates for the new Alvin W. Vogtle nuclear reactors in Georgia.

Southern subsidiary Georgia Power Co. has announced plans to "adjust key milestones" on the construction of Unit 3 at the nuclear plant expansion in response to an increase in COVID-19 cases.

"Since October, the site has seen a significant increase in COVID-19 cases, consistent with the broader regional and national rise in cases," Georgia Power said in a Jan. 11 news release. "This increase, combined with other productivity challenges, continues to impact construction production and the pace of testing activity completion."

Georgia Power, which owns 45.7% of the nuclear plant, and primary project contractor Southern Nuclear Operating Co. Inc. announced they are "analyzing the schedule for key milestones, including the start of hot functional testing and fuel load for Unit 3." While the project team plans to adjust the dates for these milestones, Georgia Power said it expects to meet the November 2021 and November 2022 in-service dates for units 3 and 4, respectively.

Mizuho Securities USA LLC said it anticipates a seven-month delay from the Georgia Public Service Commission's approved in-service dates for the units and a "$2.0 billion total project cost overrun."

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"While the company continues to target a regulatory in-service date of November 2021 for Unit 3, they are running short of time in the calendar," Mizuho analyst Paul Fremont wrote in a Jan. 13 research report. "For prior nuclear projects, it has taken roughly one year between the start of hot functional testing ... to commercial operation of the plant. Based on these standards, Georgia Power's previous schedule of beginning [hot functional testing] in January 2021 and commercial operation in November 2021 already looked aggressive."

Prior to Georgia Power's update, Scotia Capital (USA) Inc. analyst Andrew Weisel noted that the Vogtle project "brings one-of-a-kind execution risks" for Southern.

"[W]e are cautiously optimistic that additional cost overruns and delays will be modest, given that it is late in the innings, and it should not affect the company's long-term earnings power, thanks to strong regulatory support from the commissioners," Weisel wrote in a Jan. 5 report.

Georgia Power announced in mid-October 2020 that the construction of Unit 3 at the Vogtle plant is 94% complete following the successful completion of cold hydro testing. The project, however, has faced cost hurdles and delays throughout the construction process, including workforce reductions in 2020 resulting from the COVID-19 pandemic.

"The company does not mention construction cost revisions in its press release, but we believe that the inability to meet production goals will likely result in an increase in the cost estimate to complete the project," Fremont wrote.

The analyst said he anticipates Southern will announce additional construction costs and update the schedule during a February earnings call.

The independent Vogtle Monitoring Group said in a June 2020 filing with the Georgia PSC that Georgia Power and Southern Nuclear were "highly unlikely" to meet the regulatory approved in-service dates for Vogtle units 3 and 4.

In its 23rd semiannual Vogtle Construction Monitoring report, Georgia Power said its share of the total project cost increased to $8.5 billion from $8.4 billion during the first half of 2020.

In a November 2020 interview with S&P Global Market Intelligence, Southern Chairman, President and CEO Thomas Fanning said he was confident the project would meet its regulatory approved in-service dates despite the potential for more COVID-19 impacts.

"In fact, as we moved from the aggressive schedule to the expected schedule, one of the things we did was [plan for] essentially a historic constant level of COVID on the site," Fanning said. "So, we budgeted for COVID if you will. Now whatever comes will likely occur in a sine wave, right? There may be a week or two that may be higher, then a week or two that may be lower. But we have budgeted for a certain presence of the virus through the completion of Unit 3 and [Unit] 4."

Oglethorpe Power Corp., Municipal Electric Authority of Georgia and City of Dalton Georgia also own interests in the nuclear plant.

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

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Board Staff Interrogatory #61

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 46-47

Preamble:

On pages 46-47 of the Concentric Report, Concentric discussed its views regarding the impact of the Pickering NGS retirement and associated transformation of its workforce and operations on OPG's ability to forecast and plan for operations, particularly beginning in 2025 and 2026. On page 46 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Are Concentric's comments solely related to nuclear generation, or do they extend to regulated hydroelectric generation as well?

b) Please confirm that OPG undertook a multi-year business transformation initiative that was reviewed in the 2014-2015 Payment Amounts Proceeding.[1]

c) Does Concentric agree that OPG's historical experience with corporate business transformation should enhance OPG's ability to forecast its operations even factoring in the retirement of Pickering NGS? Please explain your response.

Response

Response prepared by Concentric Energy Advisors

a) Concentric's comments are in regard to the Pickering Retirement. While challenges related to the retirement of a large generation stations would likely exist regardless of the type of generation, Concentric's views the challenges related to the Pickering retirement as differentiated due to the size of the facility as well as the specialized nature of nuclear operations.
b) Confirmed.

[1] EB-2013-0321.

c) While there are likely lessons learned from the prior transformation initiative that OPG can apply, there are significant differentiating factors between the two exercises. Some of these differences are noted at pages 46-47 and footnote 66 of the report. This includes the fact that the prior initiative:

(i) involved a transformation without significant redeployment of employees across different positions (whereas the Pickering closure will trigger redeployment on a larger scale),
(ii) occurred over a longer time period (approximately four years),
(iii) involved no involuntary terminations for represented employees (whereas the Pickering closure will include involuntary terminations within the provisions of collective agreements),
(iv) was of a smaller scale (2,000 employees versus 3,000 employed),
(v) was well advanced at the time OPG sought to set rates reflecting its outcome (whereas the Pickering closure impacts are all currently forward looking),
(vi) and was focused on corporate support functions (rather than direct operations).

For the Pickering closure downsizing, the transition of qualified employees from former Pickering positions to other parts of the organization will be a complex process, and will need to be done in a manner that minimizes operational disruption to the Darlington nuclear power plant.

Board Staff Interrogatory #62

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 46

Preamble:

On page 46 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) If an appropriate number of existing staff are allocated to the remaining facilities, and focused on those facilities, how will downsizing pose an adverse risk on operational effectiveness and efficiency for OPG?

Response

Response prepared by Concentric Energy Advisors.

In following the downsizing provisions of OPG's collective agreements, redeployment of staff is required as a result of applying seniority rights for employees and other applicable provisions. These staff movements will require significant effort and planning to ensure knowledge transfer and training for many employees. In addition, the station requirements and technology are different at Darlington versus Pickering, such that this will have the greatest impact on employees directly involved in maintenance and operations. Additionally, OPG will need to manage any retention risks for key personnel as the downsizing approaches. Overall, OPG will have to ensure safe and reliable operations at Pickering until shutdown (and through the subsequent safe storage period) with the need to prepare employees for transitions to new positions at Darlington and related organizations in order to ensure effective and efficient operations across the organization after the Pickering shutdown.

Board Staff Interrogatory #63

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 48-49

Preamble:

On page 48 the Concentric Report, Concentric stated:

> 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.
>
> A recent report released by Ottawa predicts more intense precipitation, increased risk of tornadoes and wildfires in the Ottawa area due to climate change.

On page 49 of the Concentric Report, Concentric further stated:

> Scientists have also expressed high confidence that streamflow regimes will shift and that daily extreme precipitation will increase in Canada.

Question(s):

a) How is the risk of more intense precipitation referred to likely to impact production at OPG's hydroelectric generating facilities over the 2022-2026 period?

b) To date, what evidence is there of increased forest fire activity in Ontario, and how have forest fires impacted OPG's generating stations? Please identify what forest fires have impacted OPG's generating stations, the station(s) impacted, and the date(s) of each occurrence.

c) Did Concentric consider the potential availability of Z-factor treatment in its assessment of OPG's risk profile with respect to climate change-related events.

Response

a) More intense precipitation typically increase river flow for a short period of time. The flow during this time may exceed OPG's turbine capacity as hydroelectric generating station turbines are not sized to capture rare flow events. OPG's spillways would however have sufficient capacity to safely by-pass the increased flows around the hydropower stations. An increase in daily extreme precipitation is

more likely to impact OPG production by causing localized flooding within the communities and damaging transmission and distribution infrastructure, which could result in lower demand for periods of time.

> The Expert Panel on Climate Change Risks and Adaptation Potential identifies the risk to infrastructure as the top climate change risk for Canada ranking it as overall the highest risk in terms of consequences and second highest in terms of likelihood.[1] This report points to evidence including already increased insurance payouts for extreme events and increasing costs to the National Disaster Mitigation Program (Council of Canadian Academies, 2019). The risks of climate change and extreme precipitation are also well reported within the insurance industry.[2]

b) OPG does not have a databse of forest fire activity in Ontario or the historical impacts to its facilities. In 2012, OPG's Wawaitin Generating Station was closed due to a forest fire near Timmins ON that burned roughly 31 000 hectares.[3] In 2016 a grassland fire endangered OPG's Lennox Generating Station.[4]

> Fires also indirectly impact OPG's facilities by damaging transmission infrastructure impacting OPG's ability to provide energy to the grid. Examples include the fires in West Nipissing in May of 2020[5] and northwest Ontario in 2011.[6]

Part c Response prepared by Concentric Energy Advisors

c) Yes, Concentric did consider the availability of a Z factor under OPG's IR methodology for the regulated hydroelectric business. Under this provision, OPG may request rate relief for unforeseen events after exceeding a materiality threshold currently set at $10 million. Concentric did not consider this a significant factor in its risk assessment because:
   (1) Concentric is generally not aware of any other North American hydroelectric generator operating under an IR plan that would necessitate a Z factor, so

[1] https://cca-reports.ca/wp-content/uploads/2019/07/Report-Canada-top-climate-change-risks.pdf
[2] https://www.canadianunderwriter.ca/insurance/extreme-precipitation-events-have-always-occurred-but-are-they-changing-1004196651/
[3] https://toronto.citynews.ca/2012/05/25/raging-forest-fire-leads-to-state-of-emergency-in-timmins/
[4] https://www.toronto.com/news-story/6807230-crews-battle-large-wildfire-near-ontario-power-generation-plant/
[5] https://northernontario.ctvnews.ca/power-restored-in-west-nipissing-after-forest-fire-prompts-outage-1.4948185#:~:text=SUDBURY%20%2D%2D%20Hydro%20officials%20say,battled%20a%20large%20forest%20fire.&text=%22An%20emergency%20outage%20is%20required,local%20wildfires%20in%20the%20area.
[6] https://www.tdworld.com/overhead-transmission/article/20961633/hydro-one-crews-rebuilding-transmission-lines-destroyed-by-forest-fire-in-northwestern-ontario

other utilities would be able to file for rate relief without a materiality threshold, and

(2) it is not clear whether various types of climate change caused impacts would meet the OEB's definition of an unforeseen event or how such impacts would compare against the $10 million threshold.

Board Staff Interrogatory #64

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / page 59

Preamble:

On page 59 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) In Concentric's view, would a temporary decline in one of the measures likely result in a downgrade of OPG's credit rating as assessed by the credit rating agencies?

b) How big of a decline in the core ratios would Concentric view as being necessary to cause a downgrade?

Response

Response prepared by Concentric Energy Advisors

a) Our understanding is that, as a general matter and depending on the severity of any decline in credit metrics, the rating agencies such as Moody's and S&P typically may be willing to look beyond a short-term decline in credit ratios as long as there is reason to believe the decline is indeed a short-term change and that credit ratios will be restored to levels that support the rating within a reasonable period. However, Concentric expects that the specific application of this principle, including what constitutes a short-term change, will depend on the specific circumstances of each company and a rating agency's view of the risks faced by it. Therefore, it is ultimately uncertain whether a decline in OPG's credit metrics over a given period of time is likely to result in a credit rating downgrade action.

b) Concentric expects that if OPG experiences declines in its core ratios that are consistent with the rating agencies downside scenario, this could lead to a negative credit action. In its July 17, 2020 report on OPG, S&P states "We 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%." Moody's Investors Services lists as one of its "factors that could lead to a

downgrade" the following: "A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 12% on a sustained basis." In its April 16, 2020 report, DBRS did not assess a specific credit impact that could trigger a downgrade.

Board Staff Interrogatory #65

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 65

Preamble:

On page 65 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) What proportion of the assets of each of these Canadian entities is outside of Canada? Of the assets that are outside of Canada, what proportion is in the U.S.? Please provide the same breakdown for revenues and profits for each of these Canadian entities.

Response

Response prepared by Concentric Energy Advisors

Chart 1: Non-Canadian Portion of Revenues, Profits, and Assets for Canadian Utilities in Concentric Proxy Group

Company	Most Recent Data	Revenues	Profits	Assets	Notes
Emera Inc.	2020	72%	76%	78%	[1]
Fortis Inc.	2020	59%	64%	66%	[2]
Algonquin Power & Utilities Corp	2019	95%	N/A	90%	[3]

[1] Per Emera Inc.'s 2020 Annual Report, at 99-101. Concentric utilized "Net Income Attributable to Common Shareholders" as a proxy for "profits" and "Property, Plant, and. Equipment" as a proxy for "assets".
[2] Per Fortis Inc.'s 2020 Annual Report, at 17, 79, and 80. Fortis does not appear to report a geographic breakdown of "profits". Therefore, Concentric calculated non-Canadian profit based on the ratio of ITC, UNS, and Central Hudson operating income to Fortis' total operating income.
[3] Per Algonquin Power & Utilities Corp's 2019 Annual report, at 116. Algonquin does not appear to report "profits" by geographic segment.

Board Staff Interrogatory #66

Interrogatory

Reference:
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 69-71

Preamble:

On pages 69-71 of the Concentric Report, Concentric provided an analysis of what it considers the main DVAs related to OPG's regulated nuclear operations. It provides a list and description of these accounts.

Question(s):

a) Please confirm that Concentric's recommended equity thickness for OPG's regulated operations on a stand-alone basis pertains to the combination of prescribed (i.e. regulated) nuclear and hydroelectric generation assets and operations. If not, please explain.

b) Please explain why Concentric did not also consider the DVAs related to regulated hydroelectric operations in its analysis.

Response

Response prepared by Concentric Energy Advisors

a) Confirmed.

b) Concentric considered deferral and variance accounts ("DVAs") related to OPG's regulated hydroelectric operations in its analysis. For instance, on page 32 of Concentric's report, Concentric stated "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." The discussion of DVAs on page 69-71 of Concentric's report focused on the nuclear facilities in further reflection on the OEB's conclusions in the EB-2016-0152 Decision and Order (at 102-103) regarding the risk-mitigating properties of OPG's nuclear DVAs.

Board Staff Interrogatory #67

Interrogatory

Reference:
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 71-72

Preamble:

On pages 71-72 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Given that OPG, as an electricity generator, is at the front end of the supply chain from producer to end consumer, please identify what costs, and what associated DVAs, OPG has that are analogous to the Group 1 DVAs of Ontario electricity distributors.

b) Please explain the analysis that Concentric used. Was its analysis based on a count of the DVAs, or did it consider the quantum of revenues recorded in Group 1 versus Group 2 accounts?

c) Did Concentric take into account the magnitude of DVA balances relative to the revenue requirement of the firm (i.e. taking into account the scrutiny, regulatory lag and risk of denial of recovery of DVA balances on cash flow and various credit metrics of OPG relative to Ontario electricity distributors)? Did Concentric take into account the timing of dispositions and recovery of DVA balances, between Group 1 versus Group 2 accounts, and also in comparing OPG's DVAs versus those for Ontario electricity distributors? Please explain your response.

d) Did Concentric come to its conclusion that "OPG has relatively greater risk of cost recovery for its deferral and variance accounts than do other electric utilities in Ontario" solely on its qualitative judgement that: "[b]ecause the disposition of Group 2 deferral and variance accounts involves a greater degree of regulatory scrutiny than Group 1 accounts"? If there were other quantitative or qualitative considerations used by Concentric in reaching its conclusion, please provide an explanation, and any necessary data used by Concentric in reaching its conclusion.

Response

Response prepared by Concentric Energy Advisors.

a) The majority of OPG's accounts would be classified as "Group 2" accounts. Concentric understands the Group 1 deferral accounts for electricity distributors to be available to track the flow through cost of power variances between the customer and the IESO. OPG does not have such variance accounts. OPG, however, has other types of costs that are more similar to a flow through such as GRC, Taxes, variations in revenue as a result of water conditions. In some respects the GRC Variance Account, the Income and Other Taxes variances account, and the Water Conditions Variance Account are similar to a Group 1 deferral account.

b) As discussed on page 71 of Concentric's Report, we considered the general comparability of OPG's deferral and variance accounts to other regulated electric utilities in Ontario. Concentric observed that the majority of OPG's DVAs would be classified as Group 2 accounts, which require a prudence review by the OEB before the utility is allowed to recover these costs. By contrast, Group 1 accounts do not require a prudence review. Concentric also reviewed a sample of other electric utilities in Ontario and determined that those companies have a mix of Group 1 and Group 2 DVAs. On that basis, Concentric concluded that OPG has relatively greater risk of cost recovery for its DVAs than do other electric utilities in Ontario.

c) No, Concentric's analysis did not consider the type of analysis referenced in the question. See part b) above.

d) Yes.

Board Staff Interrogatory #68

Interrogatory

Reference:
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 72-73 / Figures 19-20
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / Exhibit 1

Question(s):

a) Please identify the source of the data shown in Figure 19.

b) Please confirm that Figure 20 is derived from the data contained in Exhibit 1 of Concentric's report. If not, please explain and provide the data used.

c) Please confirm that, in Figure 20, for each utility, the white space above the bar of % Hydro Production (shaded) and/or % Nuclear Production (solid) represents generation owned and operated by each utility and powered by other fuel sources (coal, natural gas, biomass, multi-fuel, wind, solar).

d) Please confirm whether all of the utility generation represented by the white space above the bar is regulated, unregulated, or a mix of regulated and unregulated generation.

e) If the white space includes unregulated generation for other comparator utilities, please explain why Concentric showed only the regulated portion of OPG's generation portfolio in Figure 20.

Please provide an updated version of Figure 20, and a table in Excel format showing the data, presenting the percentage of generation by fuel type (e.g. hydroelectric, coal, steam, wind, solar, biomass, gas) and distinguishing between regulated and unregulated generation for OPG and all comparator utilities (i.e. a 100% bar chart).

Response

Response prepared by Concentric Energy Advisors

a) The data reflected in Figure 19 of the Concentric report is derived from S&P Global Market Intelligence (formerly SNL Financial).

b) Confirmed.

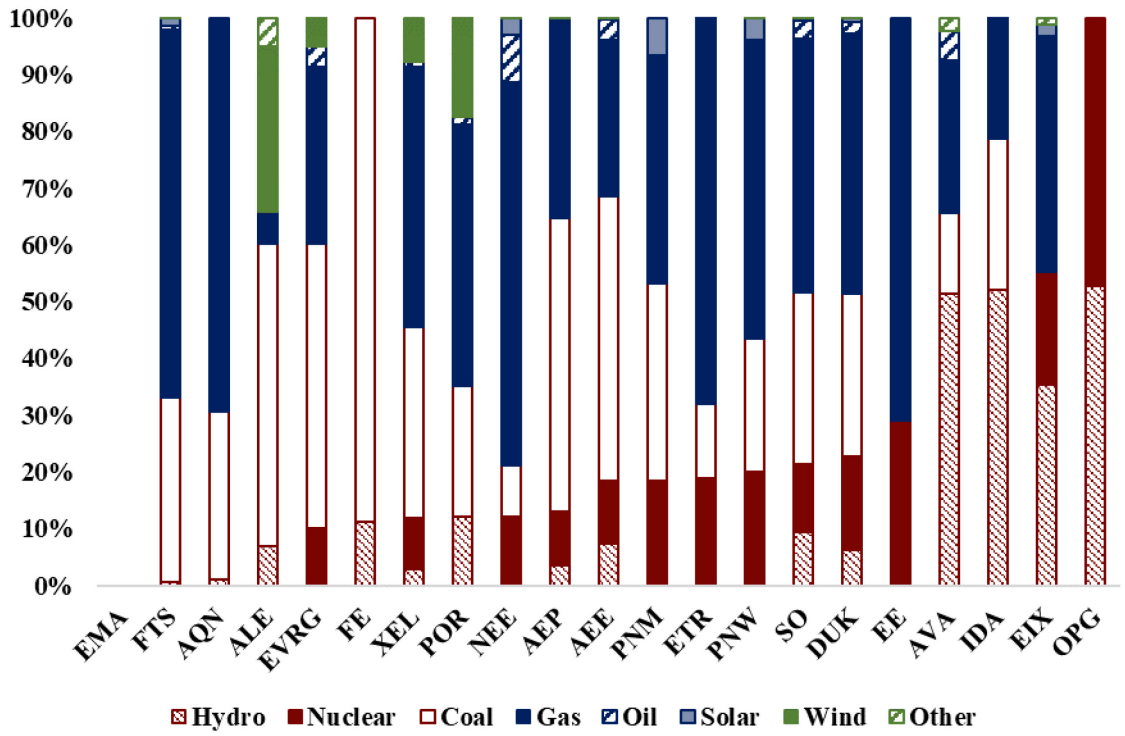
c) Confirmed.

d) The utility generation represented by white space above the shaded and/or solid bars in Figure 20 of the Concentric Report is regulated generation.

e) The white space above the shaded and/or solid bars in Figure 20 of the Concentric Report does not include unregulated generation.

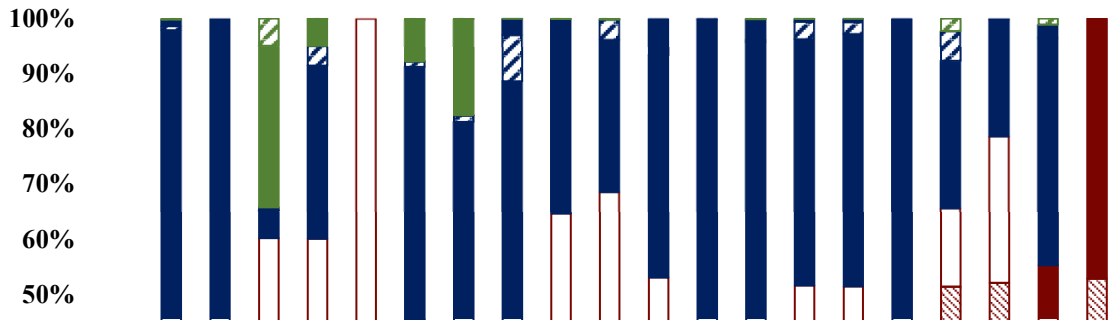
f) Please see the table below and Attachment C1-Staff-68 (excel file) for the requested information. Please note that, as described in the response to parts (d) and (e) above, the analysis reflects only regulated generation. Please also note that data for Emera, Inc. ("Emera") is not available from S&P Global Market Intelligence. Accordingly, Emera is shown as 0 percent in the Chart below and Attachment C1-Staff-68.

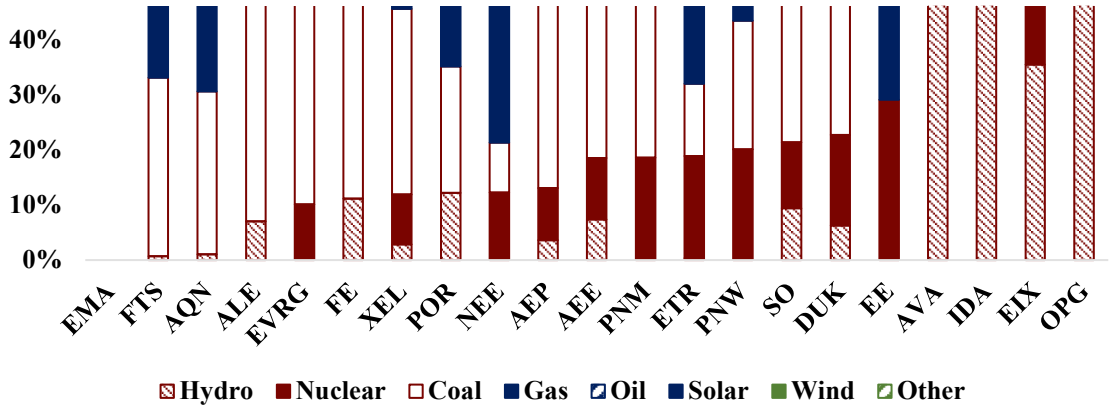
Chart 1: Generation Mix (MW)



Filed: 2021-04-19
EB-2020-0290
Exhibit L-C1-01-Staff-068
Attachment 1

Ticker	Hydro	Nuclear	Coal	Gas	Oil	Solar	Wind	Other
EMA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FTS	0.68%	0.00%	32.38%	64.83%	0.71%	1.25%	0.00%	0.15%
AQN	1.07%	0.00%	29.50%	69.43%	0.00%	0.00%	0.00%	0.00%
ALE	7.01%	0.00%	53.23%	4.98%	0.04%	0.56%	29.24%	4.93%
EVRG	0.05%	10.02%	50.05%	31.36%	3.57%	0.03%	4.91%	0.02%
FE	11.11%	0.00%	88.89%	0.00%	0.00%	0.00%	0.00%	0.00%
XEL	2.87%	9.03%	33.61%	45.75%	0.98%	0.01%	7.48%	0.28%
POR	12.16%	0.00%	22.92%	46.21%	1.17%	0.04%	17.37%	0.12%
NEE	0.00%	12.21%	9.04%	67.38%	8.41%	2.95%	0.00%	0.01%
AEP	3.59%	9.47%	51.62%	35.14%	0.08%	0.06%	0.00%	0.04%
AEE	7.36%	11.15%	50.01%	27.65%	3.65%	0.04%	0.00%	0.14%
PNM	0.00%	18.54%	34.59%	40.19%	0.00%	6.68%	0.00%	0.00%
ETR	0.34%	18.49%	13.15%	67.86%	0.16%	0.01%	0.00%	0.00%
PNW	0.00%	20.04%	23.35%	52.39%	0.33%	3.78%	0.00%	0.10%
SO	9.37%	11.97%	30.34%	44.64%	3.09%	0.58%	0.00%	0.00%
DUK	6.27%	16.39%	28.81%	45.79%	2.12%	0.62%	0.00%	0.01%
EE	0.00%	29.04%	0.00%	70.60%	0.00%	0.37%	0.00%	0.00%
AVA	51.45%	0.00%	14.10%	26.83%	5.34%	0.00%	0.00%	2.28%
IDA	52.14%	0.00%	26.47%	21.25%	0.14%	0.00%	0.00%	0.00%
EIX	35.44%	19.85%	0.00%	41.09%	0.30%	2.23%	0.00%	1.10%
OPG	52.85%	47.15%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%




40%
30%
20%
10%
0%
EMA
FTS
AQN
ALE
EVRG
FE
XEL
POR
NEE
AEP
AEE
PNM
ETR
PNW
SO
DUK
EE
AVA
IDA
EIX
OPG
Hydro
Nuclear
Coal
Gas
Oil
Solar
Wind
Other

Board Staff Interrogatory #69

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 63
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / Exhibit 2.2

Preamble:

On page 63 of the Concentric Report, Concentric noted that it considered that ownership of generation assets included in rate base was one factor for inclusion of a holding company in the proxy group.

The only two operating companies listed in Exhibit 2.2 of the Concentric Report that are described as being vertically integrated, and thus having electricity generation are Florida Power and Light Co. and Gulf Power Co., both subsidiaries of NextEra Energy Co. For both Florida Power and Light Co. and Gulf Power Co., the authorized equity thickness is shown as N/A. In calculating the average equity thickness at the holding company level, it appears that N/A values are excluded.

Question(s):

a) Please confirm that NextEra Energy Co.'s equity thickness is based solely on the authorized equity thickness for Pivotal Utility Holdings Inc., a natural gas distributor.

b) Please confirm that the analysis of equity thickness (and hence also of debt thickness) for the Moody's proxy group is based solely on natural gas and electricity distribution utilities (i.e. there is no generation reflected in the equity thickness numbers calculated for the Moody's proxy group).

Response

Response prepared by Concentric Energy Advisors.

a) Not confirmed. While Pivotal Utility Holdings Inc. is the only operating subsidiary of NextEra Energy, Inc. ("NextEra") with an authorized equity ratio listed on Exhibit 2.2 of the Concentric Report, we also studied the historical actual equity thickness of (1) NextEra's operating utility subsidiaries and (2) NextEra, the publicly-traded holding company. Both of those analyses reflect equity thickness data that is not limited to just Pivotal Utility Holdings Co. As shown on Exhibit 3.2 of the Concentric

Report, our analysis of the actual equity thickness of NextEra's operating utility subsidiaries also includes data for Florida Power & Light Company and Gulf Power Company. Further, our analysis of the actual equity thickness of NextEra, the publicly-traded holding company, definitionally reflects all of NextEra's business operations, not just Pivotal Utility Holdings Inc.

b) Not confirmed, as described in the response to part (a), above.

Board Staff Interrogatory #70

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 1

Preamble:

Concentric noted that the OEB adjusts for changes in risk through changes in the equity thickness. In other jurisdictions, differences in relative risk between firms or sectors are accounted for through allowing different ROEs.

OEB staff notes that the differences in risk can be accounted for through adjusting either the ROE and / or the equity thickness, in order to satisfy the Fair Return Standard. However, it is often more practical to alter either the ROE or the equity thickness as opposed to varying both parameters.

OEB staff notes that Concentric's analysis considers solely the authorized and actual equity thickness (and similarly the authorized and actual debt thickness) of OPG and of the holding and operating companies in the two proxy groups. There is no data or analysis provided on the allowed or achieved ROEs of the firms in the comparator groups.

Question(s):

a) Does Concentric agree that, for two firms of comparable risk, the Fair Return Standard may be satisfied even if the allowed equity thicknesses are different, so long as the allowed ROEs are offsetting?

b) Please explain why Concentric has not considered differences in allowed and achieved ROEs for the firms in the proxy groups in order to ascertain that these firms are "similar enough" to each other and to OPG.

c) If Concentric has conducted analysis on the allowed and achieved ROEs for the holding and operating companies in its proxy groups, please provide the analysis and all pertinent data. Please provide the data in working Microsoft Excel format, where possible.

Response

Response prepared by Concentric Energy Advisors

a) Yes, within a reasonable degree, an allowed ROE and capital structure can be offsetting while satisfying the fair return standard. Both impact two prongs of the fair return standard: the financial integrity of the utility; and the ability to attract capital. Methodologies used to estimate the impacts on the cost of equity for changes in the equity ratio include: Modigliani-Miller, Miller, and Hamada. There are tradeoffs along a spectrum of allowed returns and equity ratios. At a point where excessive debt threatens the solvency of the firm, shareholder returns increase sharply. Two firms with the same business risk but different equity ratios will have different equity costs.[1]

b) Concentric did not consider allowed and achieved ROEs for the proxy companies as a basis for determining whether these companies were similar enough to OPG. Screening for utilities with allowed ROEs at OPG's level would have resulted in few, if any, comparator companies. As explained in Concentrics's report, "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." Those screening criteria are: regulated generation assets in rate base; regulated nuclear/or hydroelectric generation; regulated revenue and net income greater than 60%; regulated electric revenue and net income greater than 80%; and an investment grade credit rating similar to OPG's. Concentric also considered a second proxy group, based on Moody's peers for OPG (pages 65-68). We believe these are sufficient for screening purposes, and are consistent with screening criteria typically applied by Concentric in cost of capital analyses.

c) Concentric has not conducted this analysis.

[1] New Regulatory Finance, Roger A Morin, Public Utilities Reports, 2006, pp. 453-459

Board Staff Interrogatory #71

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 1

Preamble:

On page 1 of the Concentric Report, Concentric stated:

> 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…

Question(s):

a) Concentric refers to "heightened risk for OPG". How does Concentric define "risk … on an absolute basis" as used above?

Response

Response prepared by Concentric Energy Advisors

a) By "absolute basis," Concentric is referring to its analysis of OPG's risk profile on a stand-alone basis (as compared to Concentric's comparative analysis of peer utilities).

Board Staff Interrogatory #72

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Attachment 1 / p. 3

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> 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.

Question(s):

a) Has OPG or Concentric performed financial modeling for the 2022-2026 period using various levels of equity thickness?

b) If yes, please provide the results of the modelling, summarizing assumptions made, and showing the specific impact on credit metrics of each scenario tested. Which credit metrics were most affected, and what are the potential implications on OPG's financial and operational health?

c) How do the results of the scenarios compare to OPG's credit metrics for the 2017-2021 period?

Response

a) Neither OPG or Concentric have completed any such analysis
b) N/A
c) N/A

Board Staff Interrogatory #73

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / Exhibits 1.1-5.1

Question(s):

a) Please provide all of the Exhibits 1.1 to 5.1 in Microsoft Excel format, if available.

Response

a) Please see Attachment Staff-73 for Exhibits 1.1 to 5.1 of the Concentric report in Microsoft Excel format.

VECC Interrogatory #7

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report

Please provide the evidentiary basis for the following statements:

a) "*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*" (page 1)
b) "*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-adverse and safety conscious*..." (page 6) . Specifically, please define "*safety conscious*" in terms of measurable and observable market activity.

Response

Response prepared by Concentric Energy Advisors

a) See, for example, EB-2009-0084, which discusses the application of one cost of equity to all utilities in Ontario and the application of different capital structures to different types of utilities.

b) "Safety conscious" is in reference to a change in investor tolerance for risk, where investors shift to lower risk investments. This was evidenced in 2020 as investors moved substantial sums from equities into bonds in response to volatility and uncertainty in equity markets resulting from the pandemic. Chart 1 below collected by Morningstar illustrates this point. Investors in U.S. mutual funds and ETFs moved over $300 billion out of U.S. and international equities, while moving $1.2 trillion into lower risk bond and money market funds. According to Morningstar: "U.S. equity funds' $241 billion of outflows in 2020 was 4 times the previous record of $58 billion set in 2015, and their negative 2.6% organic growth rate was the sharpest hit to total assets in data going back to 1993. The calendar-year outflows for 2020 were more than the four next-worst

years combined (2015, 2011, 2009, and 2012)."[1]

Chart 1

U.S. Category Group	Estimated Net Flows Dec. 2020 ($Mil)	1 year ($Mil)	Assets ($Bil)
U.S. Equity	(14,488)	(241,151)	10,859
Sector Equity	17,233	56,318	1,144
International Equity	489	(63,248)	3,783
Allocation	(2,557)	(82,311)	1,394
Taxable Bond	73,296	441,399	5,102
Municipal Bond	12,216	55,362	939
Alternative	(690)	8,422	225
Commodities	930	37,629	166
All Long Term	86,429	212,419	23,613
Money Market	(20,101)	678,170	4,320

[1] https://www.morningstar.com/articles/1017899/us-fund-flow-records-fell-in-2020

VECC Interrogatory #8

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report

a) What empirical evidence do the authors rely upon to support the theory that shedding older Pickering assets and relying on refurbished Darlington Assets creates a perception of increased risk by market participants?
b) Is it Concentrics's view that companies that restructure to eliminate older less productive assets while investing in refurbishing newer ones are viewed by investors as becoming riskier? If so please provide examples of this phenomena.

Response

Response prepared by Concentric Energy Advisors

a) Please see the response to L-C1-01-Energy Probe-9 part (b).

b) Concentric does not hold that view as a rule. In the case of OPG, however, where the Company is in the midst of a $12.8 billion refurbishment of the Darlington station that the investment community has identified as having significant execution risk and during a time at which the diversity of its generation fleet will be reduced, with a large portion of the workforce subject to redeployment across the two stations, the Company is exposed to increased risk.

VECC Interrogatory #009

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.58

a) Other than the antidotal event provided at page 58, what empirical evidence do the authors have that climate change is: (1) leading to a warming trend in Lake Ontario; (2) that if so this trend will lead to more algae blooms; and (3) that an increase in algae blooms in Ontario increases the risk of shutdown of OPG's nuclear fleet?
b) Given the extraordinary safety engineering of a nuclear plant please explain why it is not more likely that climate change will reduce nuclear production risk vis-à-vis investments in carbon based or other energy type production?
c) Assuming climate change is leading to increased demand/desirability of non-carbon-based energy why is it not likely that government climate change will lead to less risk for owners of nuclear energy production.
d) What empirical evidence is Concentric relying on to support the notion climate change leads to a comparative risk increase to OPG's nuclear fleet assets?

Response

Response prepared by Concentric Energy Advisors

a) For clarification, the risks related to warmer lake temperatures are discussed at page 48 (not 58) of Concentric's report.

Please see the following Attachments for demonstration of the impacts of climate change on Lake Ontario temperatures and the corresponding impacts on algae blooms:

Attachment 1: An Assessment of the Impacts of Climate Change on the Great Lakes (Environmental Law and Policy Centre)
Attachment 2: Lake Ontario Water Temperature in a Changing Climate (Ouranos)
Attachment 3: Climate Change Indicators: Great Lakes Water Levels and Temperatures (United States Environmental Protection Agency)

Attachment 3 notes that since 1995, the average surface water temperatures have increased slightly for each of the Great lakes. Attachment 2 projects that Lake Ontario water temperatures will increase by anywhere from 0.5-1.9 degrees Celsius by 2070.

Algae blooms are increasing in severity worldwide and experts believe climate change is playing a major role in this. Climate change is having an effect on many of the factors that influence algal blooms, such as nutrient loading and water temperature. In addition, high lake surface water temperatures could result in longer summer stratification of the water and lead to increased algae growth.[1]

Algae blooms impact the nuclear operating stations by clogging or reducing the efficiency of cooling water systems, potentially resulting in a shutdown or unit derate. For example, on July 22, 2018, four reactors at the Pickering Nuclear station were forced off-line when algae blooms blocked cooling water intakes.[2] As algae events increase in severity and frequency, OPG faces a greater risk of a shutdown resulting from algae blooms.

b) Please see the responses to SEC-36 and Staff-55.

c) Please see the responses to SEC-36 and Staff-55.

d) With regard to the impact of climate change on the operational risk of OPG's nuclear facilities, please see Exhibit C1-1-1, Attachment 1, at 48, where Concentric discusses the risk related to warmer lake temperatures and related impacts and their effects on the operation of nuclear stations. Please also see part (a), above.

[1] Attachment 1, pp 25-31
[2] https://www.durhamregion.com/news-story/8800254-is-algae-the-new-nuisance-neighbour-for-the-pickering-nuclear-station-/

ENVIRONMENTAL LAW & POLICY CENTER

An Assessment of the Impacts of Climate Change on the Great Lakes

The Environmental Law & Policy Center, in concert with the Chicago Council on Global Affairs, commissioned the following scientists and experts to produce this report pro bono to educate policymakers and the public about the significant changes affecting the Great Lakes, and the vital importance of taking actions now to protect our natural resources.

Donald Wuebbles, *University of Illinois*
Bradley Cardinale, *University of Michigan*
Keith Cherkauer, *Purdue University*
Robin Davidson-Arnott, *University of Guelph, Ontaria, Canada*
Jessica Hellmann, *University of Minnesota*
Dana Infante, *Michigan State University*
Lucinda Johnson, *University of Minnesota, Duluth*
Rob de Loë, *University of Waterloo, Ontario, Canada*
Brent Lofgren, *NOAA GLERL*
Aaron Packman, *Northwestern University*
Frank Seglenieks, *Environment and Climate Change Canada*
Ashish Sharma, *University of Notre Dame and University of Illinois at Urbana-Champaign*
Brent Sohngen, *The Ohio State University*
Michael Tiboris, *Chicago Council on Global Affairs*
Daniel Vimont, *University of Wisconsin, Madison*
Robyn Wilson, *The Ohio State University*
Kenneth Kunkel, *North Carolina State University and NOAA CICS-NC*
Andrew Ballinger, *North Carolina State University and NOAA CICS-NC*

Table of Contents

Executive Summary 1

1. Introduction 5

1.1 Importance of the Great Lakes 6

1.2 Climate change: From global to the Great Lakes region 7

1.3 Potential risks and vulnerabilities for the Great Lakes 8

1.4 Public perception of the Great Lakes: Value and vulnerability 8

2. Regional climate change in the Great Lakes 9

2.1 Air temperature changes and trends 10

2.2 Precipitation trends 13

2.3 Extreme events 13

2.4 Cold-season processes (snow and ice) 14

3. Changes in the Great Lakes 16
3.1 Changes in lake temperature and stratification 16
3.2 Great Lakes ice cover trends 17
3.3 Hydrologic trends 18
3.4 Changes in lake level 20
4. Changes in Great Lakes watershed hydrology 21
4.1 Climate change effects on lake hydrology 21
4.2 Land use / land cover change 22
4.3 Agricultural watersheds and agricultural impacts 23
4.4 Urban watersheds and urban impacts on the Great Lakes 24
4.5 Water quality impacts on the Great Lakes 25
5. Impacts on lake ecology 26
5.1 Mixing and oxygenation 27
5.2 Biodiversity and invasive species 27
5.3 Nutrient loading and algal blooms 29
5.4 Fish 31
5.5 Wildlife 34
5.6 Coastal ecosystems 36
5.7 Coastal processes 37
6. Public and economic impacts of changes to the Great Lakes 39
6.1 Shipping 40
6.2 Water supply 40
6.3 Infrastructure 41
6.4 Recreation 43
6.5 Public health 45
6.6 Impacts on Indigenous People in the Great Lakes Basin 46
6.7 Industrial needs for water 46
7. Conclusions 48
References 49

Executive Summary

Introduction

Climate change is causing significant and far-reaching impacts on the Great Lakes and the Great Lakes region. In recent years, our planet has experienced some of the warmest temperatures ever recorded, record-breaking weather extremes, powerful storms, increasing tragic flooding from rising sea levels and associated storm surge, huge wildfires, and continued melting of glaciers and polar sea ice. The accelerating pattern of changes in the Earth's climate is affecting the Great Lakes. Here, we draw on the array of existing research to assess how the shifting global climate impacts the unique Great Lakes region.

The Great Lakes have an enormous impact, seen and unseen, on the 34+ million people who live within its Basin. These millions of people rely on the freshwater lakes for drinking water, fisheries, recreation, and commerce and industry. The Great Lakes contain 5,500 cubic miles of freshwater, one of the very largest freshwater resources in the world. The Great Lakes support one of the world's largest regional economies similar to those of whole developed nations. Agriculture, industrial manufacturing, fishing, and recreation together form an economic engine. Regional fisheries alone represent a $7 billion per year industry. Tourism generates $16 billion more.

Heavy human use over the past two centuries has taken its toll in the forms of habitat loss and fragmentation, influxes of invasive species, and polluted air, water, and sediments. Soil and nutrient runoff from agricultural fields and concentrated animal feedlot operations (CAFOs) imperil water quality and wildlife populations in many parts of the basin, threatening public and wildlife health and the economic vitality of the region. Climatic changes now underway further stress these ecosystems, alternatively raising and lowering lake levels and threatening the region in new ways.

The Great Lakes sustain remarkable populations of fish and habitats for wildlife. More than 170 species of fish live in the lakes, streams, rivers, and connecting waterways. Trout, sturgeon, walleye, lake whitefish and other varieties of fish are once again becoming plentiful among the five Great Lakes. The basin's ecosystems support wolves and moose while providing resting and breeding grounds for large flocks of migratory birds and waterfowl. More than 3,500 species of plants and animals use its large network of streams, lakes, inland wetlands, coastal marshes and forests. Many of these species are rare or are found nowhere else.

The Great Lakes are large enough to themselves influence weather in the region. The Lakes moderate temperatures throughout the year, helping to cool nearby lands in the summer and warm them in winter. Their humidity feeds cloud cover and precipitation both over the lakes and downwind. That causes both "lake effect" snowstorms, and summer rainfall that provides ideal growing conditions for orchards in Michigan's "fruit belt."

Climate change presents challenges to the Great Lakes, with complicated effects and inter-relationships.

Air Temperature Increases

The Great Lakes region has tracked global increases in temperature and outpaced trends in some parts of the contiguous United States. Between 1901-1960 and 1985-2016, the Great Lakes basin has warmed 1.6°F in annual mean temperature, exceeding average changes of 1.2°F for the rest of the contiguous United States. By the end of the 21st century, global average temperatures are expected to rise an additional 2.7°F to 7.2°F, depending on future greenhouse gas emissions, with corresponding changes in the Great Lakes region.

Heavy Precipitation and Flooding

A warmer atmosphere holds more moisture, increasing the frequency and intensity of heavy rain and snow events. Overall U.S. annual precipitation increased 4% between 1901 and 2015, but the Great Lakes region saw an almost 10% increase over this interval with more of this precipitation coming as unusually large events. In the future, precipitation will likely redistribute across the seasons. We expect wetter winters and springs, while summer precipitation should decrease by 5-15% for most of Great Lake states by 2100.

These increases in precipitation will likely increase flooding across the Great Lakes region. In cities with abundant roofs, concrete, and other impermeable surfaces, this will likely

damage homes, roadways, and other infrastructure. In rural areas, intense rains and melting snows will increase runoff and erode soils. In rural areas, increased flooding will also cause soil erosion. In combination with more unpredictable precipitation and warmer temperatures, these effects could seriously curtail Midwestern agricultural production.

Extreme Weather

Climate change is causing more extreme weather across the United States. Heat waves have become more common since the 1960s while extreme cold temperatures have generally decreased. Intense summer storms occur more often as temperatures rise.

Extreme weather events have already taken their toll on the Midwest. The 2012 Midwestern heat wave and drought caused more than $30 billion in economic damage, 123 deaths, and harmful long-term health impacts across most of the central and western United States.

Extremely warm days (above 90°F) will increase for states bordering the Great Lakes, especially in the southern parts of the region. By century's end, the region will experience 30 to 60 additional days each year of these extremely warm temperatures. Areas within the Great Lakes Basin will see an increase of 17 to 40 extremely warm days as annual average temperatures continue to rise.

Meanwhile, in states surrounding the Great Lakes, the number of extremely cold days (with temperature less than 32°F) will decrease significantly. Lake effect snowfalls could be even more dramatic, particularly across the Lake Ontario snowbelt in upper western areas of New York state where three- and four-feet snowstorms are already routine.

Agriculture, Irrigation, and Decreased Crop Yields

Changes in seasonal precipitation are already affecting farmers in Midwestern states, with planting delays caused by spring flooding and excessively wet soil conditions. Delayed planting puts crops at greater risk during hotter and drier conditions later in the growing season, and that increases the demand for irrigation to mitigate crop losses. Hot temperatures interfere with pollination in corn and other crops, thereby reducing yields.

Yet, even with increased water management in agricultural watersheds, climate change will likely reduce crop yields for both soybean and maize by 10% - 30% by mid-century in the southern parts of the Great Lakes watershed. Soybean and maize production will likely move northward.

Urban Issues

In the summer, high temperatures and heat waves cause poorer air quality, which harms public health, especially for the most vulnerable people – the elderly and children with asthma. For the many millions of people living in urban areas across the Great Lakes states, heat waves and summer air pollution events increase the risk for heat-related illness, respiratory diseases, and death.

Projected increases in extreme precipitation will likely exacerbate flooding, especially in winter, spring, and during summer thunderstorms. Extreme winter rain events in 2017 and 2018 led to serious flooding. Rain events exceeding 6 inches now occur regularly, exceeding the capacity of culverts and storm sewers to handle runoff. Under-resourced communities in low-lying, flood-prone areas have become vulnerable to infrastructure damage, transportation barriers, and displacement from homes due to these intensified floods.

Water Quality and Consumption

Climate change will likely threaten drinking water quality and place great stress on water infrastructure. For example, in southern Wisconsin, extreme precipitation could rise by 10% to 40%, overloading water treatment infrastructure, increasing sewer overflows, and increasing the quantity of water-born pathogens flowing into streams, rivers, and Lake Michigan.

The Great Lakes have higher levels of E. coli bacteria than other U.S. coastal regions. This untreated effluent is a public health hazard and economically costly to mitigate. Cities like Chicago have spent enormous sums to protect against water pollution. Nutrients (primarily nitrogen and phosphorous) run off from farms into surface waters during intense rain events. These excess nutrients threaten human health both directly (e.g., "blue baby" syndrome) and

indirectly by contributing to toxic harmful algal blooms in shallow water bays of the Great Lakes and the "dead zone" in the Gulf of Mexico that has decimated shellfisheries.

In 2011, Lake Erie experienced the largest harmful algal bloom in its recorded history, with peak intensity more than three times greater than any previously observed blooms. In 2014, 500,000 people in the Toledo area were without safe local drinking water supplies for 72 hours because of toxic algae blooms in western Lake Erie. Algal blooms will likely become more frequent in the future as higher temperatures and heavy precipitation mix heavy nutrient loads with warmer waters. These pollutants have dramatically raised the cost of water treatment.

Lake Ecology

Climate change has already increased bacteria levels in the Great Lakes, as the water warms earlier in the spring and warming contributes to vertical mixing that changes lake ecosystems. Sewer overflows, the dumping of ship ballast water, and nutrient runoff from agriculture and industry all contribute to growth of bacteria and several invasive species in the lakes. Heavier rainstorms and warmer weather exacerbate these challenges.

Hundreds of new species of pathogenic bacteria, viruses, protozoa, and non-native species could be introduced and flourish in the warming conditions, displacing local native species. While climate change may not directly drive lake species extinct, the persistence of many native species will be threatened as they confront more invasive species, species replacements, and proliferating pest and disease organisms.

Fish

Fish respond sensitively to water temperature, assembling in distinct cold, cool, and warm water groupings. This means that warmer temperatures, seasonal weather shifts, and storms that bring a quick influx of water will all affect fish species. The geographic ranges of fish, demographics within species, system productivity, species-specific productivity, the spatial arrangement of species, and their physiological state and performance will all change in response.

For example, game fish like bluegill, smallmouth bass, largemouth bass, and brown bullhead have migrated poleward as water warms in those areas. This may increase diversity of species in some Ontario lakes by as much as 81% by the end of the century. Growth rates of yellow perch, lake whitefish, and many others, however, are likely to decrease.

Wildlife

The Great Lakes region supports many species of mammals, birds, amphibians, reptiles, and macroinvertebrates. As air temperatures increase and precipitation patterns shift, habitat conditions, soil moisture, and other conditions will shift, thereby driving some wildlife species northward and others westward. Individual species however, will respond in different ways to local conditions such as ice cover on lakes and specific patterns of regional precipitation.

Among mammals, moose may be especially vulnerable to climate change. In Minnesota, moose populations have already declined precipitously. Moose density is expected to also decline at southern parts of the Ontario region and increase at northern extents. Milder winters increase overwinter survival in white-tailed deer allowing them to expand northward into habitats historically dominated by moose.

With water levels falling and temperature rising, diseases like botulism will increase, spreading more disease and killing more birds that consume fish. Birds could also suffer from phenological mismatch, as the insect species they relied on for food hatch earlier with warmer springs or decline as vegetation shifts northward.

Shipping, Power Generation and Shorelines

Fluctuating lake levels resulting from climate change greatly affect the ability of ships to safely navigate shallow portions of the Great Lakes' channels and harbors. Both lower lake levels and higher water temperatures pose technical challenges for power generation. Changing lake levels affect marinas, docks, and shoreline homes and other buildings.

Recreation and Beach Closures

The Great Lakes Commission estimated that boating contributed approximately $9 billion to the Great Lakes economy in 2003. Boating activities such as skiing could be affected by warming temperatures, shifts in the length of seasons, and changes in lake levels.

It's become common in recent years for beaches in Chicago and Michigan to close or be under swim advisories because of bacterial contamination. Beach closures are expected to increase as heavy precipitation exacerbates issues associated with runoff and pushes up bacterial counts as well as algal blooms and E. coli alerts.

Conclusion

We should not and cannot take the vast natural resources of the Great Lakes for granted. Allowing the Great Lakes to be degraded through human activities, including climate change, is not an option. For economic, aesthetic, recreational, and ecological reasons, the Great Lakes should be restored to be healthy, unpolluted, and productive. We must reduce the effects of climate change on the Great Lakes.

Public support for protecting the Great Lakes is strong across the region. Scientific analyses clearly show that climate change has already greatly affected the region and that these impacts will continue and expand as the pace of climate change accelerates. It is critical that we recognize the importance of one of the world's most abundant freshwater resources and ensure its protection for generations to come.

1. Introduction

The North American Great Lakes are amongst the largest freshwater resources on our planet. The five Great Lakes (Superior, Michigan, Erie, Huron, and Ontario) cover a total area of more than 94,000 square miles (243,000 square kilometers) with over 9,000 miles (14,500 kilometers) of shoreline. They hold 5,500 cubic miles (22,700 cubic kilometers) of freshwater, which is enough water to cover the area of the continental United States with almost 10 feet (3 meters) of water. They also include 5,000 tributaries and have a drainage area of 288,000 square miles. The watersheds comprising the Great Lakes Basin span major areas of the United States and Canada (see Figure 1).

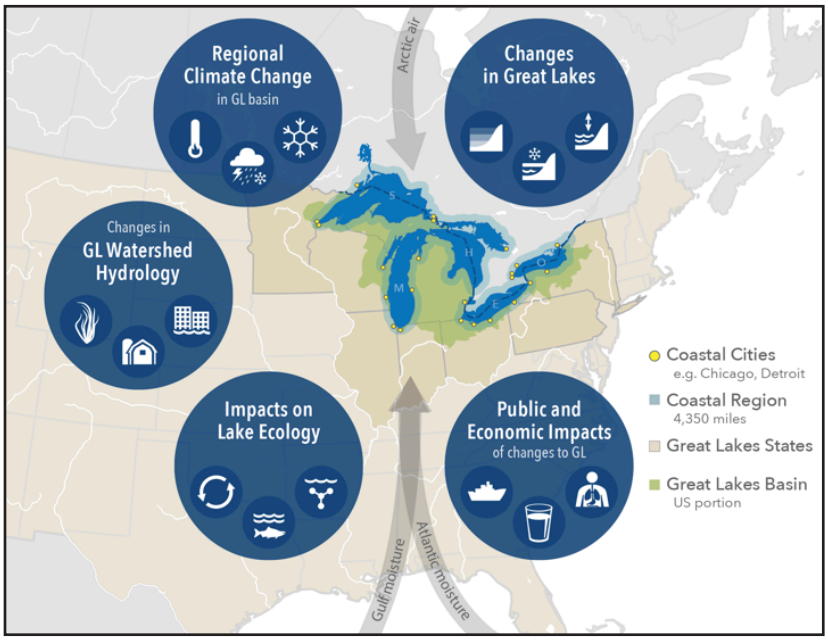


Figure 1. A schematic diagram highlighting the focus areas and themes of the assessment and the major impact pathways.

The Great Lakes are extremely important both to humans and to wildlife – they are an abundant freshwater resource for water supplies, industry, shipping, fishing, and recreation, as well as a rich and diverse ecosystem. However, over the last two centuries, the Great Lakes and the broader basin have been significantly affected by human activities, leading to habitat loss and fragmentation, invasive species, and an influx of biological and chemical pollutants that present substantial environmental challenges (e.g., Riley, 2014). These impacts have impaired water quality, threatened wildlife populations, and jeopardized the health and economic vitality of the region. Now, climate change is adding new challenges and significant additional stress to conditions in and surrounding the Great Lakes (Melillo et al., 2014; Sharma et al., 2018).

This report assesses the current and projected impacts of climate change on the Great Lakes. This assessment aims to evaluate the effects of climate change on the Great Lakes, its shorelines, regional land use, biodiversity, and urban cities on the lakes. The assessment does not aim to address all of the basins feeding the lakes or the states around the lakes. This study provides an update on prior analyses of such impacts – including GLISA (2016), McDermid et al. (2015), Walsh et al. (2014), Pryor et al. (2014), Wuebbles et al. (2010), Wuebbles and Kling (2006), Wuebbles and Hayhoe (2004), Kling et al. (2003), and Lofgren et al. (2002). The Midwest chapter from Volume II of the 4th National Climate Assessment (USGCRP, 2018) also includes some discussion of the impacts of climate change on the Great Lakes; this assessment is intended to be a more thorough look at those current and potential impacts.

1.1 Importance of the Great Lakes

By total area, the Great Lakes is the largest group of freshwater lakes on Earth, and second largest by total volume, containing 21% of the world's surface fresh water by volume. They contain 95% of the surface water in the United States and 84% of the surface fresh water available in North America (https://www.epa.gov/greatlakes/great-lakes-facts-and-figures).

About 34 million people rely on the Great Lakes for drinking water, jobs, and their way of life (their choices for recreation, etc.) — about 24 million people in the U.S. and about 9.8 million in Canada. That's roughly 8 percent of the U.S. population and 32 percent of Canada's (University of Wisconsin Sea Grant Institute 2018). The United States draws more than 40 million gallons (151 million liters) of water from the Great Lakes every day – more than half used for electrical power production, with the rest used for drinking water, industrial production, and agriculture.

The Great Lakes support one of the world's largest regional economies, including a $7 billion fishing and $16 billion tourism industry. Accounting for agricultural production within the region, commercial and sport fishing, industrial manufacturing, and tourism and recreation, the Great Lakes' economic activity surpasses that of most developed nations. A third of the basin's land is used for agriculture. Tourists spend hundreds of millions of dollars each year in the basin with more than 60 million people annually visiting the many parks that dot the shores. The lakes and their waterways serve as shipping conduits to transport bulk cargo from the basin to the markets of the world. Canals, rivers, straits, locks and channels connect the lakes together to form one of the busiest shipping areas in the world. Over 150 million tons of cargo are transported over the Great Lakes each year, supporting 44,000 jobs (https://www.mlive.com/news/muskegon/index.ssf/2009/03/sat_transporting_goods_by_ship.html). Since 1959, more than 2 billion metric tons of iron, coal, steel, oil, grains, and other products have been shipped over the Great Lakes.

A large variety of fish and wildlife species is supported by the waters and lands of the Great Lakes Basin. More than 170 species of fish inhabit the Great Lakes, their tributaries, and connecting waterways. These include lake trout, lake sturgeon, lake whitefish, walleye, landlocked Atlantic salmon, and associated forage fish species. The Great Lakes basin also provides critical breeding, feeding, and resting areas, as well as migration corridors, for waterfowl, colonial nesting birds, neotropical migrants, and many other species of migratory birds. In general, the region of the Great Lakes contains an immense network of streams, lakes, inland wetlands, coastal marshes, and forests. These habitats support more than 3,500 species of plants and animals, including more than 200 globally rare species and 46 species found nowhere else in the world. The Great Lakes Basin provides the diverse habitats needed by more than 180 fish species to complete their life cycles. A critical stopover region for more than 350 migratory bird species, the basin provides resources to sustain hundreds of millions of birds along their migratory routes each year. In addition to supporting fish and wildlife populations, the diverse habitats of the basin provide numerous critical ecological services, including water filtration and storage, flood control, nutrient cycling, and carbon storage. These diverse habitats are also important to the culture of the native people in the Great Lakes region.

The Great Lakes also play an important role in influencing local weather patterns across the region. The Great Lakes influence daily weather by 1) moderating temperatures in all seasons, producing cooler summers and warmer winters; 2) increasing cloud cover and precipitation over and just downwind of the lakes during winter; and 3) decreasing summertime convective clouds and rainfall over the lakes (Scott and Huff, 1996; Notaro et al., 2013).

These effects range from moderate (e.g., mild cooling breezes that help lakeshore orchards and vineyards flourish) to extreme (e.g., harsh lake effect snow and ice storms that close airports, shut down interstate freeways, and knock out power grids). The Great Lakes therefore provide diverse benefits and challenges to the weather of the surrounding urban and rural landscapes.

1.2 Climate change: From global to the Great Lakes region

The global climate continues to change rapidly compared to the pace of natural variations that have occurred throughout Earth's history. Trends in globally averaged temperature, sea level rise, upper-ocean heat content, land-based ice melt, Arctic sea ice, depth of seasonal permafrost thaw, and other climate variables provide consistent evidence of a warming planet. These observed trends are robust and have been confirmed by multiple independent research groups around the world (USGCRP, 2017; IPCC, 2013).

The global annual-average temperature has increased by 1.8°F (1.0°C) from 1901 through 2016 (as calculated from instrumental records over both land and oceans) (USGCRP, 2017). Sixteen of the 17 warmest years in the measurement record (which spans over 130 years) occurred in the period from 2001 to 2017. (The one exception in the highest 17 warm years was 1998, a major El Niño year.). The global average temperature for 2016 was the warmest on record, surpassing 2017 and 2015 by a small amount. The years 2017 and 2015 far surpassed the 4th warmest year on record, 2014, by 0.29°F (0.16°C), four times greater than the difference between 2014 and the next warmest year, 2010 (NCEI, 2016).

The frequency and intensity of extreme heat and heavy precipitation events are increasing throughout most of the world, including the Great Lakes region. These trends are consistent with the expected response to a warming climate and are likely to continue. Observed and projected trends for some other types of extreme events, such as floods, droughts, and severe storms, have more variable regional characteristics. The shift to warmer winters, greater winter precipitation, and more intense rainfall is likely to increase flooding in Great Lakes cities.

The 4th U.S. National Climate Assessment (USGCRP, 2017), building upon prior assessments of the science (e.g., IPCC, 2013; Melillo et al., 2014) and extensive new evidence, concludes that it is extremely likely that human activities, especially emissions of greenhouse gases and land use change, are the dominant cause of global warming since at least the mid-20th century. For the last century, there are no convincing alternative explanations for the observed warming supported by observational evidence. Natural variability cannot account for the amount of global warming observed over the industrial era. Changes in solar output and internal variability can only contribute marginally to the changes in climate observed over the last century, and there is no convincing evidence for natural cycles that could explain the changes in climate over the last century. The warming over recent decades cannot be attributed to the Sun; in fact, extremely accurate satellite observations show that solar output has declined slightly over the last four decades (USGCRP, 2017).

Global climate is projected to continue to change over this century and beyond. The magnitude of climate change beyond the next few decades will depend primarily on the amount of greenhouse (heat-trapping) gases emitted globally and on the remaining uncertainty in the sensitivity of Earth's climate to those emissions. With significant reductions in the emissions of greenhouse gases, the global annually averaged temperature rise could be limited to 3.6°F (2°C) or less. Without major reductions in these emissions, the increase in annual average global temperatures relative to preindustrial times could reach 9°F (5°C) or more by the end of this century (USGCRP, 2017).

Similarly, annual average temperature over the contiguous United States increased by 1.8°F (1.0°C) for the period 1901–2016 and is projected to continue to rise. As with the global changes, there have been marked increases in temperature extremes across the United States. The number of high temperature records set in the past two decades far exceeds the number of low temperature records. Heavy precipitation events in most parts of the United States have also increased in both intensity and frequency since 1901. There are important regional differences in these trends, with the largest increases occurring in the U.S. Northeast and Midwest.

1.3 Potential risks and vulnerabilities for the Great Lakes

Prior studies have shown that global climate change is already affecting both the climate of the Great Lakes region and the physical behavior of the Great Lakes themselves (e.g., Melillo et al., 2014, and other reference above). Regional weather extremes in temperature and precipitation are intensifying (Winkler et al., 2012). In recent decades, a number of changes in the climate of the Great Lakes region have been documented, including a significant warming trend (Schoof, 2013; Zobel et al., 2017a,b), an increase in extreme summertime precipitation (Kunkel et al. 2003, 2012; Zobel et al., 2018), changing lake levels (Gronewold et al., 2013a), and changing trends in lake-effect snows (Norton et al., 1993; Kunkel et al., 1999; Bard and Kristovich, 2012; Notaro et al., 2013; Clark et al., 2016; Suriano and Leathers, 2017). The region has also recently witnessed unprecedented extreme changes in the timing of precipitation and runoff, with important implications for flooding, soil erosion, nutrient export, and agricultural practices (Carpenter et al., 2017; Kelly et al., 2017). Warm, wet winters are producing extensive early-season flooding, which threatens people and infrastructure. Associated runoff and soil erosion are also a concern for future agricultural productivity.

Further changes in climate projected over the coming decades are likely to add significantly to the vulnerabilities and risks to the Great Lakes and the Great Lakes Region. There are many vulnerabilities and risks discussed in this assessment, including potential changes in lake water levels and their effects on coastal erosion and wave damage, effects on lake temperature and stratification, effects on water quality, effects on the ecology and wildlife in both the lakes and the region, and effects on the public and the economy of the Great Lakes region. Figure 1 highlights the basic topics and themes that are covered throughout the rest of this report.

1.4 Public perception of the Great Lakes: Value and vulnerability

A binational poll conducted by the International Joint Commission's Water Quality Board in 2015 indicates that the vast majority (85%) of the residents in the Great Lakes basin feel it is important to protect the Great Lakes, largely for the provision of drinking water and the fact that they are a valuable resource with economic, recreational, and environmental importance (IJC, 2016). Residents were less certain whether the health of the Great Lakes is increasing, getting worse, or staying the same. The poll indicated that 56% believe the lakes are getting worse or staying the same. When asked about problems facing the Great Lakes and the surrounding tributaries, residents were most likely to identify pollution (roughly 50%), while a significant minority (31%) did not know what the biggest threat might be. Although the majority of respondents (78%) felt they personally played a role in protecting the Great Lakes through their own education and decision making, many (30%) were unsure what specifically they could do. These high levels of concern and personal responsibility exist despite the fact that only 42% of residents in the basin use the lakes for leisure or recreational purposes.

Residents responding to the poll did not directly identify climate change as a threat to the Great Lakes. However, many of the top issues mentioned by residents are exacerbated by climate change, in particular the trends in the

region for increasing temperature and precipitation moving into the future. For example, residents were concerned about pollution (including runoff) and invasive and endangered species, threats that become greater under the impacts of a changing climate. Agricultural runoff, a major threat to lakes, and in particular Lake Erie, occurs during spring storms and will worsen as the intensity of spring rainfall events increases (Michalak et al., 2013). Similarly, the movement and loss of species is often exacerbated by shifting habitat needs as the climate warms (Ryan et al., 2018).

This binational poll was replicated in 2018 (IJC, 2018), affirming that public support for protecting the Great Lakes remains high (up by 3% points to a total of 88%). This report also indicated that 55% of residents are willing to pay more for consumer products as a result of regulations designed to restore and protect the Lakes. In a new question about the top ten issues facing the Great Lakes, 73% of residents ranked climate change as having an extremely negative impact, just behind other issues exacerbated by climate change (e.g., invasive species, algae blooms, and runoff). Residents in the Great Lakes were not keen to engage socially or politically in these issues (only ~30%), but the majority were willing to be more careful about what they dispose down the drain (83%) and with their water use (74%).

An annual poll on climate change perception in the United States finds that 70% of Americans believe global warming is happening, and these beliefs are becoming increasingly certain over time (Leiserowitz et al., 2018; Howe et al., 2015). For the Great Lakes states and provinces, these numbers ranged from a low of 64% (in Indiana) to a high of 77% (in New York) (Marlon et al., 2018). In addition, approximately 60% of Americans were worried about global warming and believe that it is affecting weather in the United States (increasing extreme heat, droughts, flooding, and water shortages) (Leiserowitz et al., 2017). For the Great Lakes states, this sense of worry about climate change ranged from a low of 49% (in Indiana) to a high of 67% (in New York). At the county level, concern and belief increased more in urban areas than in rural areas (Marlon et al., 2018). In general, beliefs about climate change were largely driven by political orientation and ideology (Hornsey et al., 2016), explaining why we see this variation in the Great Lakes states where political ideology is more evenly divided among liberals, moderates, and conservatives relative to portions of the rest of the country (IJC, 2016).

2. Regional climate change in the Great Lakes

The climate is changing over the Great Lakes and is projected to change much more over the coming century. This section summarizes the observed and projected changes in climate variables such as near-surface air temperature and precipitation over the Great Lakes and bordering U.S. states. The methodology used in these analyses is similar to that used in the 4th National Climate Assessment (USGCRP, 2017), and is based on the analyses of observational datasets for past changes and from modeling and downscaled datasets for projections produced for NCA4. Projections use a weighting system for global climate models, that are then statistically downscaled for temperature and precipitation at about 6 km resolution across the continental United States. The methodology is described in more detail in the Supplementary Material.

The projected global average temperatures are expected to rise an additional 2.7°F to 7.2°F if greenhouse gas emissions from fossil fuels in energy and transportation systems continue to rise over the 21st century (see Figure 2). Future pathways range from assuming continued large dependence on fossil fuels as a high scenario, called Representative Concentration Pathway 8.5 W/m2 (RCP8.5), to a low scenario, RCP4.5, assuming rapid reductions in the use of fossil fuels after mid-century, to a very low RCP2.6 scenario, assuming major emissions-

reduction actions. As discussed below, the Great Lakes regional climate shows strong signals of weather extremes that get even stronger in the future (refer to the Supplementary Material for details on the selection of historical observational datasets and the ensemble of statistically downscaled future projections).

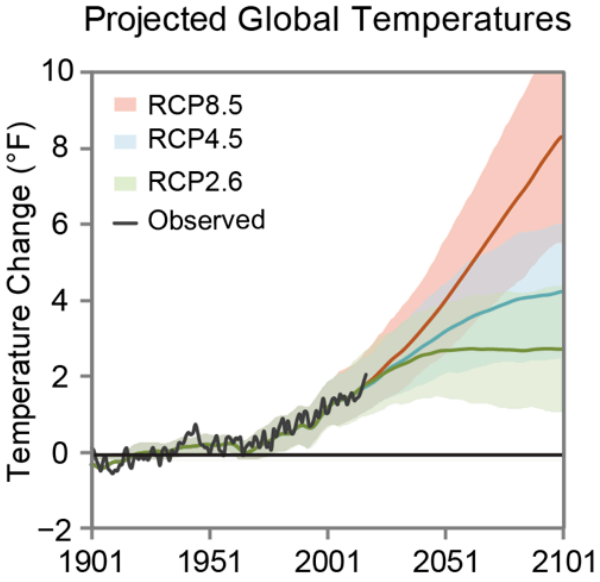
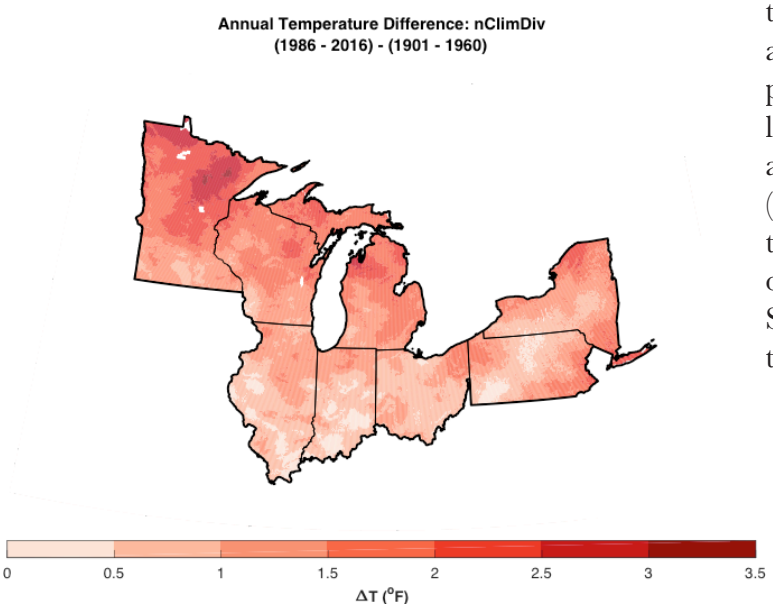


Figure 2. Multi-model simulated time series from 1900 to 2100 for the projected change in global annual mean surface temperature relative to 1901–1960 for a range of the Representative Concentration Pathways (RCPs). These scenarios account for the uncertainty in future emissions from human activities (as analyzed with the 20+ models from around the world used in the most recent international assessment [IPCC, 2013]). Source: USGCRP (2017)

2.1 Air temperature changes and trends

Of the many indicators of climate, temperature is one of the most important, because it affects our lifestyles and our decision-making. For example, temperature data are used by builders and insurers for planning and risk management and by energy companies and regulators to predict demand and to set utility rates. As the most widely and consistently observed climate variable, air temperature is very convenient for users. Long-term temperature trends are also an important indicator of the changes occurring in climate.



In the Great Lakes region, the U.S. states bordering the Great Lakes have seen an overall increase in annually averaged temperature of 1.4°F for the period 1985-2016 relative to 1901-1960, with the largest changes at the higher latitudes (see Figure 3 and Table 1). For the extent of the Great Lakes Basin (see Figure 1), the temperature change is 1.6°F over this time period. These trends are higher than the overall change of 1.2°F over the contiguous United States (and found globally) for the trends over these time periods (USGCRP, 2018).

Figure 3. Observed changes in annually-averaged temperature (°F) for the U.S. states bordering the Great Lakes for present-day (1986–2016) relative to 1901–1960. Derived from the NOAA nClimDiv dataset (Vose et al. 2014). Source: NOAA/NCEI.

	U.S. States Bordering the Great Lakes	Great Lakes Basin
Observed trend	1.4	1.6
2016-2045 Lower Scenario	3.0	3.0
2016-2045 Higher Scenario	3.3	3.3
2036-2065 Lower Scenario	4.4	4.4
2036-2065 Higher Scenario	5.5	5.6
2070-2099 Lower Scenario	5.7	5.8
2070-2099 Higher Scenario	9.8	10.1

Table 1. Change in annually-averaged temperature (°F) for U.S. states bordering the Great Lakes and for the smaller area of the Great Lakes basin. The observed trend is the difference for annually-averaged temperature for 1986-2016 period relative to 1901-1960. The future projections for annually-averaged temperature due to emissions from the higher (RCP8.5) and lower (RCP4.5) scenarios are shown for the periods 2030 (2016-2045), 2050 (2036-2065), and 2085 (2070-2099) time periods.

	U.S. States Bordering the Great Lakes	Great Lakes Basin
Observed trend	9.6	10.0
2016-2045 Lower Scenario	4.0	4.5
2016-2045 Higher Scenario	4.0	4.2
2036-2065 Lower Scenario	5.5	6.4
2036-2065 Higher Scenario	6.2	7.0
2070-2099 Lower Scenario	6.2	7.2
2070-2099 Higher Scenario	9.8	11.4

Table 2. Change in annual precipitation (as equivalent rainfall) (%) for U.S. states bordering the Great Lakes and for the smaller area of the Great Lakes basin. The observed trend is the difference for annual precipitation for 1986-2016 period relative to 1901-1960. The future projections for annual precipitation due to emissions from the higher (RCP8.5) and lower (RCP4.5) scenarios are shown for the periods 2030 (2016-2045), 2050 (2036-2065), and 2085 (2070-2099) time periods.

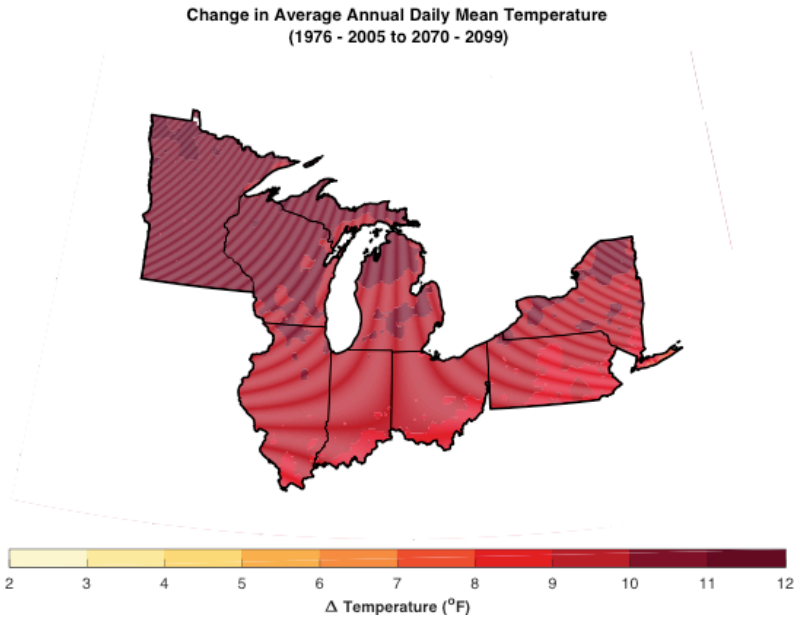
	U.S. States Bordering the Great Lakes	Great Lakes Basin
Observed (1984-2013 vs 1954-1983)	-1.93	-2.25
2020s RCP4.5	-16.49	-15.65
2020s RCP8.5	-17.87	-17.04
2050 RCP4.5	-27.94	-26.18
2050 RCP8.5	-33.17	-31.56
2080 RCP4.5	-30.48	-28.15
2080 RCP8.5	-49.08	-47.46

Table 3. Change in annual snowfall (%) for U.S. states bordering the Great Lakes and for the smaller area of the Great Lakes basin. The observed trend is the difference for annual snowfall for 1986-2013 period relative to 1954-1983. The future projections for annual snowfall are calculated based on the ensemble mean of 10 statistically-downscaled GCMs by Hybrid Delta for the higher (RCP8.5) and lower (RCP4.5) scenarios (Byun and Hamlet, 2018) associated with three 30-yr periods centered on 2020s, 2050s, and 2080s. Also, the values for the future periods represent the projected changes relative to observed mean for 1976-2005.

Land Use/Land Cover Class	% Basin	% Change 2000-2011
Developed	10.52	0.38
Agriculture	38.02	-0.27
Forest	29.55	-0.50
Grass/Shrub	3.62	0.35
Wetland	15.80	0.01
Barren	0.35	0.02
Water	2.15	0.01

Table 4. Land use and land cover for the Great Lakes basin, based on data for year 2011. Change from 2001 to 2011 is also shown. Data derived from U.S. National Land Cover Database (NLCD) for the U.S. side, and the Ontario Land Cover Compilation V2.0 for the Canadian side of the basin. (Data from SOLEC, in review).

The projected changes in annual average temperature for the U.S. states bordering the Great Lakes are shown in Figure 4 for the higher (RCP8.5) and lower (RCP4.5) emissions scenarios for the 2085 (2070-2099) time period relative to 1976-2005. The patterns of warming over these states for the 2030 (2016-2045) and 2050 (2036-2065) time periods are similar but with smaller temperature changes. Averaged over the entire Great Lakes region, slightly greater increases are projected in summer than winter, and average maximums are expected to rise slightly faster than average minimums. These seasonal variations are reversed in the northern Great Lakes region, with winter temperature rising more than summer and average minimums warming more than average maximums (WICCI, 2011; IPCC, 2013; USGCRP, 2017). Table 1 shows that projected changes in temperature for these scenarios are 3.3, 5.5, and 9.8°F (1.8, 3.1, and 5.4°C) for the 2030, 2050, and 2085 time periods for the higher scenario, and 3.0, 4.4, and 5.7°F (1.7, 2.4, and 3.2°C) for the 2030, 2050, and 2085 time periods for the lower scenario. The projected changes in temperature for the Great Lakes Basin are similar but slightly higher for the same time periods and scenarios (see Table 1). Not surprisingly, there is little difference in the projected effects on temperature over the next few decades between the different scenarios, but large differences between the scenarios by the end of the century. Similar projections along with monthly changes were found by Zhang et al. (2018). The potential societal and ecological impacts on our planet, including those associated with the Great Lakes, are likely to increase in proportion to annual average temperature (Stern et al., 2006; Melillo et al., 2014).



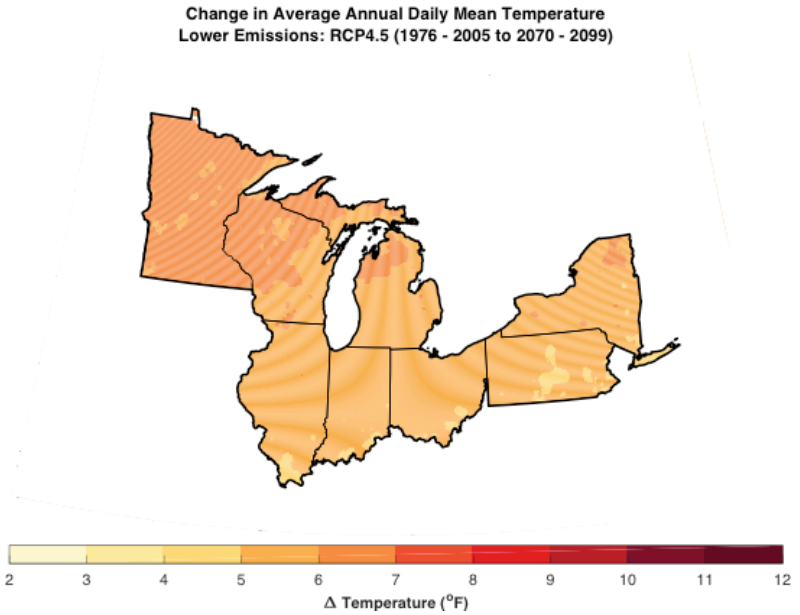


Figure 4. Projected change in annually-averaged temperature (°F) for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. Source: NOAA/NCEI

2.2 Precipitation trends

Annual precipitation averaged across the United States has increased by approximately 4% from 1901 to 2015 (USGCRP, 2017). Figure A1 shows that there is a generally positive trend for U.S. states bordering the Great Lakes in annual precipitation for present-day (1986–2016) relative to 1901–1960, but with strong local variations in the trend across the states. There is a 9.6% increase in annual precipitation averaged over these states (Table 2), while the Great Lakes Basin shows a comparable 10.0% increase. The largest increasing trends are for fall-season (~15.8% for the bordering states), with summer (9.9%) precipitation also being larger relative to winter precipitation (7.7%) and spring precipitation (7.0%).

The patterns of projected future annual precipitation changes over the U.S. states bordering the Great Lakes states and for the Great Lakes Basin for the earlier periods are similar but with smaller changes (Figure A2; Table 2). The greatest differences arise in how precipitation change is distributed across seasons, with future increases concentrated in winter and spring months for both emission scenarios, while summer precipitation decreases by 5% to 15% for most of the Great Lake states by the end of the century (Byun and Hamlet, 2018). The likely reason for this trend is that increasing warming with time will allow the atmosphere to hold more moisture and thus generate higher precipitation. As in temperatures, there is little difference in the effects between scenarios over the next few decades, but larger differences between the scenarios by the end of the century. The likely reason for this trend is that increasing warming with time will allow the atmosphere to hold more moisture and thus generate higher precipitation.

2.3 Extreme events

Along with the overall changes in climate, there is strong evidence of an increasing trend in the intensity in some types of extreme weather events over recent decades. Changes in the characteristics of extreme weather events are particularly important for human safety, infrastructure, agriculture, water quality and quantity, and natural ecosystems. For example, heatwaves have become more frequent in the United States since the 1960s, while extreme cold temperatures and cold waves have become less frequent (USGCRP, 2017). These extreme temperature conditions provide a direct risk to the public of the Great Lakes region (Patz et al., 2014). For example, the 2012 Midwestern heat wave and drought caused more than $30B in economic damage, and 123 direct deaths. It contributed to considerable long-term health impacts across most of the central and western United States (Rippey, 2015). The chances for record-breaking high temperature extremes have increased and will continue to increase as the global climate warms. Recent record-setting hot years are projected to become common in the near future for the United States, as annual average temperatures continue to rise.

Heavy rainfall is increasing in intensity and frequency across the United States and globally and is expected to continue to increase (Karl and Knight, 1998; O'Gorman and Schneider, 2009). The largest observed changes in extreme precipitation in the United States have occurred in the Midwest and Northeast. Changes in climate are increasing the likelihood for these types of severe events. Past and projected trends remain uncertain for some types of severe storm events, including the intensity and frequency of tornadoes, hail, and damaging thunderstorm winds. Tornado activity in the United States has become more variable, particularly during the 2000s, with a decrease in the number of days per year with tornadoes and an increase in the number of tornadoes on days when they do occur (USGCRP, 2017).

The number of future extremely warm days (with temperature greater than 90°F) is projected to increase for the states bordering the Great Lakes, especially in the southern parts of the region, but less so near the Lakes (Figure

A3). By the end of the century there is a projected increase of 60 extremely warm days in the Great Lakes states for the higher scenario and 30 days for the lower scenario. Areas within the Great Lakes Basin show similar trends, with an increase of 40 extremely warm days projected for the higher scenario and 17 for the lower scenario, based on an average over the basin. For midcentury, 2050s, the number of days greater than 90°F for the U.S. states bordering the Great Lakes is projected to increase by 30 days for the higher scenario and 21 for the lower (17 for the Great Lakes basin with the higher scenario and 11 for the lower). For 2085, hot days with >100°F are projected to increase by 17 days for the higher scenario and 5 for the lower scenario (8 for the Great Lakes basin with the higher scenario and 2 for the lower, relative to none in the recent 30-year period).

The number of extremely cold days (with minimum temperature less than 32°F) is projected to decrease dramatically over the century because of wintertime warming in the states bordering the Great Lakes (Figure A4). The largest decrease in freezing days is projected for the most northern states and for the Great Lakes Basin, consistent with regional variations in winter temperature trends. There is a projected decrease of 33 days for the higher scenario and 21 for the lower scenario (42 for the Great Lakes Basin with the higher scenario and 27 for the lower scenario). For midcentury, 2050, the number of days less than 32°F for the U.S. states bordering the Great Lakes is projected to decrease by 20 days for the higher scenario and 17 for the lower (25 for the Great Lakes Basin with the higher scenario and 21 for the lower). By the 2030s, the Great Lakes Basin is projected to see 15-16 fewer freezing days per year. Similarly, the frost-free season (and the corresponding growing season) should also lengthen throughout the century for these scenarios.

The number of days projected to have high temperatures under 32°F (these are days that do not get above freezing, so different than the previous paragraph) are also projected to decrease, by as many as 56 days in the Great Lakes Basin by the end of the century for the higher scenario and 31 days for the lower scenario.

The amount of precipitation coming in extreme events has already increased over the last five decades in the Great Lakes region (USGCRP, 2017), and is projected to increase further over the coming decades. The amount of precipitation occurring in storms with a 5-year return period is projected to increase by 18.7% by 2085 for the higher scenario and 10.8% for the lower scenario (20.8% and 11.3%, respectively, for the Great Lakes Basin) (Figure A5). The amount of precipitation in such extreme storms is projected to increase by 7-8% by the 2030s and by 9-12% by the 2050s. The precipitation from what are currently considered to be 1 in 50 and 1 in 100-year storms are projected to increase similarly, meaning that very large amounts of precipitation are expected from these once-unusual events.

2.4 Cold-season processes (snow and ice)

With a changing climate, both rain and snow precipitation patterns are expected to change over the Great Lakes, complicating projections of snow processes. While the increase in precipitation may lead to more snow fall in individual events, the winter warming trend across the United States will lead to a reduction in the number of snow events compared to rain events. Further, warming can lead to shifts in seasonal distributions of snow cover in the Great Lakes. As a result, rising temperatures in the Great Lakes states have had little effect on historical total annual snowfall across the region (Figure A6 and Table 3), but their effect on reducing seasonal duration of snow cover is more pronounced (Brown and Mote, 2009; Notaro et al., 2014). Some areas affected by lake effect snows have actually experienced significant increases in seasonal snowfall in recent decades (e.g., Burnett et al., 2003). Despite small overall trends in snow fall during the historical record, by the end of the century, annual total snowfall

over Great Lakes states is projected to decrease by 50% for the higher scenario and 30% for the lower scenario (Figure A7 and Table A1). This results in substantial reductions in snow cover, with days of snow depth greater than 5.9 inches (15 cm) reduced from the historical average of 61 days for the entire region to 19 days for the higher scenario or 35 days for the lower scenario by the end of the century (Chin et al, 2018; results are consistent with findings of Notaro et al., 2014). The projected snowfall reductions are not uniform in the Great Lakes states. The snowfall amounts are projected to decrease slightly less within the Great Lakes Basin in comparison to the total Great Lakes states, possibly due to lake-effect snow in the basin. Lake-effect snow is largely limited to Michigan (the upper peninsula and western parts of the lower peninsula), upper Indiana, northern Ohio, parts of Ontario to the east of Lakes Superior and Huron, and parts of New York and Pennsylvania to the east of Lakes Erie and Ontario. More southerly states in the basin will have more reduction in snow than more northerly states because of the (climatological) greater frequency of days when mean daily temperature goes above 32°F. Similarly, far northern latitudes may experience less reduction in snow cover due to the (climatological) greater frequency of days when the mean temperature stays below 32F.

Projections suggest that more precipitation will fall as rain and less as snow during the cold season, particularly in southern Great Lakes states under the high emission scenario. Changing climate is expected to shift the hydrological cycle in several ways simultaneously: increasing temperatures, decreasing snowfall, and increasing spring rainfall. This would lead to early spring snowmelt and increasing flood risks in many watersheds (Byun et al., 2018; Cherkauer and Sinha, 2010). During periods of colder temperatures, lower snow accumulations could also cause greater freezing of soils, at least in the near term, further exacerbating winter and spring flood risk, especially following rain on snow events (Sinha and Cherkauer, 2010).

LAKE EFFECT SNOWS

Some of the heaviest snowfalls on record in the United States were generated by the Great Lakes. For example, three- to four-foot snowstorms are routine in the Lake Ontario snow belt, including the upper western areas of New York in the fall and winter. On January 8, 2011, a snowband spanning virtually the entire north-south length of Lake Michigan curled into South Bend, Indiana, hammering the city with some of the highest snowfall rates ever seen outside of the Lake Ontario snow belt (https://weather.com/storms/winter/news/great-lakes-snowbelts-lake-effect-snow-records). Lake Erie has also had large effects from northeast Ohio to western New York. Prior to the U.S. Thanksgiving in 2014, a multi-day event covering the Buffalo area with up to 88 inches of lake-effect snow, bringing city activity to a grinding halt.

The ingredients for lake effect snow are straightforward and come together a number of times each fall and winter. Cold air from Canada pours over the still unfrozen, relatively warm Great Lakes. The lake moisture and instability from this temperature contrast build one or more bands of snow, which are then deposited over locations downwind from the lakes. Climate change, including warmer lake temperatures, could enhance these effects when the conditions are appropriate for snowfall. The observed trend of precipitation tending to occur in larger events throughout the Great Lakes basin could also mean larger lake effect snowfalls when the conditions are ripe.

3. Changes in the Great Lakes

Climate is a coupled surface-atmosphere process. This means that climate change alters the exchange of heat between the atmosphere and the Great Lakes. This changes the overall temperature and ice cover of the lakes, and also changes the timing of overturnings (seasonal mixing of lake water) associated with seasonal thermal changes. Although projections of climate change show increases in both precipitation and evapotranspiration in the Great Lakes Basin, observations to date have not shown significant long-term trends. The state of science on the projection of the net effect on lake level has undergone a major change of course in the last several years, changing from projections of large drops in lake level under older methodologies to smaller drops on average and the possibility of a small rise in lake levels through the end of this century.

3.1 Changes in lake temperature and stratification

Climate change in the Great Lakes involves both direct input of heat to the Lakes by increased downward longwave emissions by greenhouse gases, and inhibited loss of heat to the air by turbulent heat fluxes associated with the effects of the lakes. This should be expected to increase water temperatures within the lakes, but will also have particular influences on the temperature profile within the lakes and the phenology (timing) of the lakes' temperature structure (i.e., timing of particular events that occur during the seasonal cycle). Figure 5b shows the change in summer temperatures in the Great Lakes from 1994 to 2013 (USGCRP, 2018) – all of the Great Lakes show a significant increase over the 20 year period, especially Lake Superior.

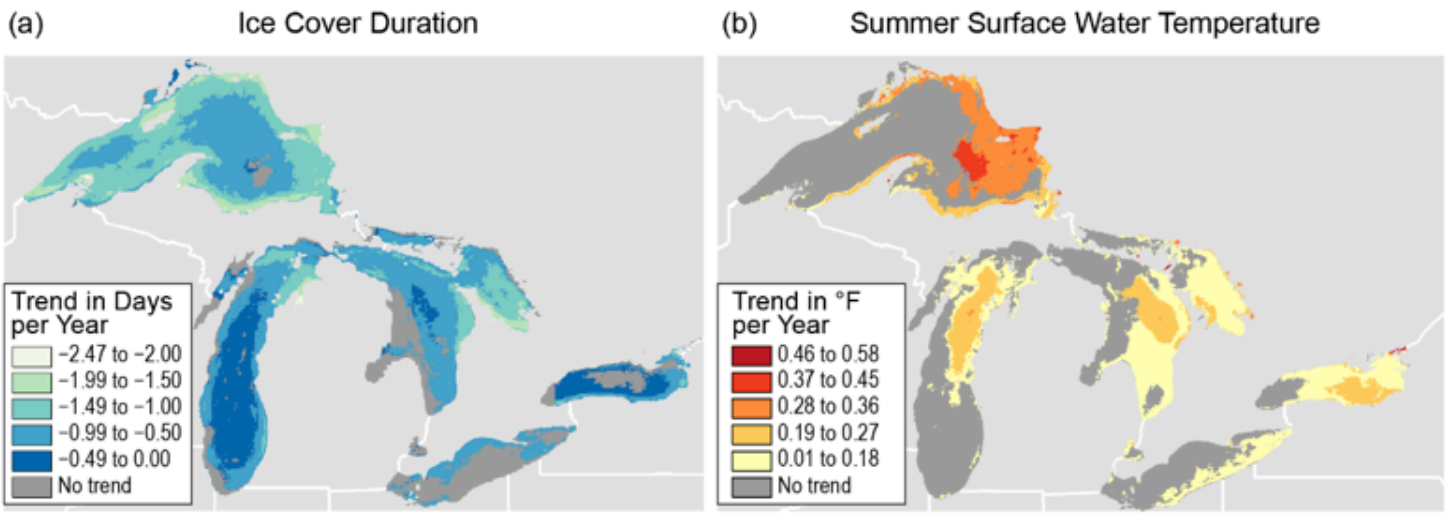


Figure 5. The duration of seasonal ice cover decreased in most areas of the Great Lakes between 1973 and 2013, while summer surface water temperature (SWT) increased in most areas between 1994 and 2013. (a) The map shows the rate of change in ice cover duration. The greatest rate of decrease in seasonal ice cover duration is seen near shorelines, with smaller rates occurring in the deeper central parts of Lakes Michigan and Ontario, which rarely have ice cover. (b) The map shows the rate of change in summer SWT. The greatest rates of increase in summer SWT occurred in deeper water, with smaller increases occurring near shorelines. Source: USGCRP 2018); adapted from Mason et al. (2016) by Kaye Lafond of NOAA GLERL.

Fresh water has its maximum density at a temperature of 4°C (39°F). This means that water at temperatures above or below this value can form a stable layer above deeper water that is closer to this temperature. Historically, the surface water of the Great Lakes has passed through this temperature threshold twice during each year. As the surface water cools from its maximum temperature of the year (usually during September), it begins to mix with warmer and less dense water at greater depths. Continued cooling makes this mixing reach even deeper into the water column until it reaches the 4°C threshold, after which further cooling produces less dense water that can form a stable layer at the surface. Ice may form, but eventually the water will warm, again causing it to mix downward until complete mixing occurs when it approaches 4 °C.

Temperature changes in the lake-atmosphere system are expected to shift the timing of these overturning episodes, as well as the timing of ice formation and melting. Lake surface temperatures simulated by Xiao et al. (2018) show that points in Lakes Superior, Michigan, and Erie reach the 4°C mixing threshold earlier in the spring and later in the fall (other lakes were not analyzed). This also leads to suppressed mixing once the temperature threshold is passed in the spring, yielding stronger vertical gradients of water temperature, and an earlier, more stable thermocline.

Lake Superior summer surface temperatures have increased more quickly than the air temperatures over land in the region (Austin and Colman 2007, Desai et al. 2009). This is believed to be due to earlier onset of summer stratification (initiated by warming beyond the 4 °C threshold, after which the warmest water is at the surface), which reinforces itself by inhibiting mixing of colder water from deeper in the lake. This mechanism is likely to continue, causing reduced stability of the lower atmosphere in the Great Lakes' vicinity during the summer.

3.2 Great Lakes ice cover trends

Ice cover on the Great Lakes has seen a slight decreasing trend between the time when systematic observations began in 1973 and 2018 based on data from NOAA GLERL. Figure 5a shows a significant decrease in duration of ice cover over many parts of the Great Lakes from 1973 to 2013. Figure 6a shows the overall time series of maximum ice coverage over the entire Great Lakes from 1973 to 2018 while Figure 6b shows the long-term trends based on this data. Lake Erie typically has the highest percentage of ice cover during a given season due to the shallow nature of the lake. Superior, Huron, and Erie are losing ice cover more quickly than the other Great Lakes over this time period.

The winters of 2013-14 and 2014-15 had plentiful ice cover and decreased the time trend found in earlier studies (e.g., Wang et al., 2012). There have been efforts to connect the extreme cold spells during those two winters with anthropogenic climate change, specifically its tendency to reduce the equator-to-pole temperature gradient by warming the poles more than the tropics (Francis and Vavrus, 2012, 2015). The understanding of these connections still has major uncertainties, however (e.g., Wallace et al., 2014). The ice cover data can be found in the online Great Lakes Ice Atlas at https://www.glerl.noaa.gov/data/ice/atlas/.

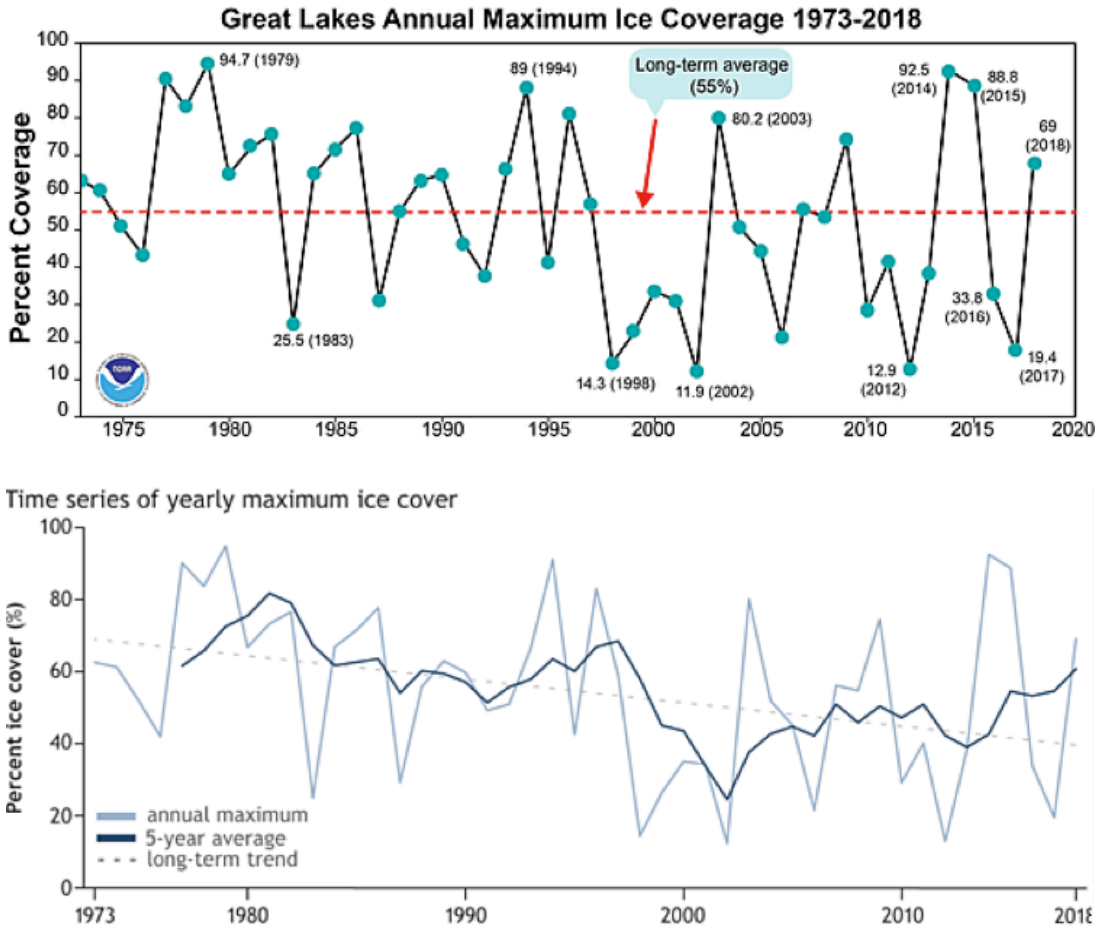


Figure 6. (a) Time series of the maximum ice coverage over the entire Great Lakes from 1973 to 2018. (b) Time series for the same data with solid line added for the 5-year running mean and a dashed line for the long term linear trend. Source: NOAA GLERL.

Ice cover is projected to decrease over the remainder of the 21st century. Croley (1990) showed reduced ice cover in spatially lumped models of each lake (i.e. without any spatial divisions within the lake). Notaro et al. (2015) showed reduced ice cover and a retreat of ice to the shallowest parts of the lakes even when complete removal is not indicated, but the model used by Notaro et al. did not consider transport of ice.

3.3 Hydrologic trends (over-lake evaporation, precipitation, runoff, groundwater, and inter-lake flows)

The recent release of the North American Great Lakes hydrometeorological database (Hunter et al., 2015; Smith et al., 2016) makes it possible to assess historical changes in the hydrometeorology over the Great Lakes. Inflows to the lakes include direct over-lake precipitation and discharge from the surrounding watersheds into each lake. Between the periods 1954-1983 and 1984-2013, over-lake precipitation decreased by 7.9% over Lake Superior, 6.8% over Lake Erie, and by 2.0% over Lakes Michigan and Huron (treated as a single lake in the database because they are hydrologically one water body). An increase of 3.5% was found over Lake Ontario. The decreases over Lakes Huron, Michigan, and Erie are strictly based on over-lake precipitation, while precipitation over both the Lakes themselves and the surrounding Great Lakes Basin increased for the same periods. The decrease in

Lake Superior precipitation corresponds to the decrease in annual precipitation over the upper peninsula of Michigan. Runoff from the lake watersheds into each lake has decreased by 8.6% for Lake Superior, and increased by 7.3% for Lake Erie and by 9.8% for Lake Ontario.

Evaporation of lake water is driven by the gradient of water vapor mixing ratio between the surface (the saturation vapor pressure corresponding to the surface water temperature) and a reference level in the atmospheric boundary layer, along with mixing by wind and turbulence. Evaporation requires energy, known as the latent heat of evaporation, and therefore is constrained by the amount of energy that the lake receives by input of shortwave radiation from the Sun, longwave radiation exchanged with the atmosphere, and sensible heat flux. This latter is heat that is transferred directly between surface and atmosphere by direct contact between molecules of different temperatures and, similar to evaporation, it is driven by a gradient of temperature between surface and atmosphere, along with strength of mixing. Because lakes have significant heat capacity, they can store energy to be released later through evaporation and other means. Thus, maximum evaporation from deep lakes occurs when the lake water is still relatively warm, while the air is much cooler, i.e., in fall and early winter. Van Cleave et al. (2014) proposed that evaporation is aided by pre-conditioning, so there is unusually high evaporation during cold periods that were preceded by unusually warm seasons or years. Annual over-lake evaporation has increased for all of the Lakes, with a minimum increase of 2.3% for Lake Ontario and a maximum increase of 7.8% for Lake Erie. Air temperature has increased most rapidly over Lake Superior and, combined with a decrease in ice cover, has resulted in a 6.5% increase in evaporation.

The Net Basin Supply (NBS) is quantified as precipitation + runoff – evaporation for each lake. Lake Superior, with decreasing precipitation and runoff and increasing evaporation has experienced a 17.5% decrease in NBS. Increases in runoff into Lake Erie have not entirely offset decreased precipitation and increased evaporation, resulting in a 7.3% decrease in NBS. Lakes Michigan and Huron have experienced a 3.0% increase in NBS, while Lake Ontario has increased by 9.5%. Change in NBS can also affect the movement of water between the lakes, with flows from Lake Superior into Lakes Michigan and Huron decreasing by 9.7%. There is little to no change between the other lakes. Discharge from Lake Ontario to the St. Lawrence River has increased by 2.8%. Connecting channel flows must, in the long run, balance the net basin supply. On shorter time scales (a few years), the net basin supply can lead to changes in lake level, which then affect connecting channel flow until an equilibrium is reached.

Three inter-basin diversions were identified by Hunter et al. (2015) as being large enough to have a potentially significant impact on basin-scale runoff. Two of these, the Ogoki Diversion and the Long Lac Diversion, shift water into the Lake Superior watershed from the Hudson Bay watershed. Historically this inflow varies from 120 to 200 m3/s, and there has been a 5.9% decrease in discharge into Lake Superior through these diversions for the period of record. The other significant diversion transfers 80 to 110 m3/s of water from Lake Michigan to the Illinois and Mississippi River basins via the Chicago Sanitary and Ship Canal. Water removed from Lake Michigan through this system has decreased by 2.5% in the period of observation.

In the future, annual precipitation is expected to increase with a general shift to wetter winter and spring conditions (Section 2.2) and more variable summers that are likely to become hotter and drier by the end of the century. Less ice cover and warmer air temperatures will continue to increase evaporation. Runoff will increase in the winter and spring, and it will decrease in the summer (Section 4). The effect of these changes on NBS is critical to determining future lake levels (Gronewold et al., 2013).

3.4 Changes in lake level

Water levels have fluctuated considerably over multi-decadal time scales. Figure 7 shows annual changes in the water levels for the Great Lakes from 1860 to 2015. The combined Lake Michigan and Lake Huron are the most variable among the Great Lakes. Lake Superior has smaller variability, especially because of its large size relative to its drainage basin. Superior's outflow is one of the drivers of Lake Michigan-Huron water level. Lake Erie's water levels generally fluctuate along with Lake Michigan-Huron's but with somewhat smaller amplitude, and causing a backwater effect by influencing the slope of the connecting channels.

Water levels across all of the Great Lakes have risen over the past several years following a period of record low levels. Lake Ontario, the farthest downstream, is driven mostly by inflow from the Niagara River but also by its own watershed. Its outflow is also regulated, dampening the water level variability somewhat, but extremely high levels in Lake Ontario during 2017 led to conflicting interests of lakeshore property owners, who wanted maximum release of water to lower water levels, and shipping interests downstream in the St. Lawrence River, who wanted at least some periods of lower flow for safer shipping. Record-breaking heavy precipitation in the basin appears to have largely driven the increases in lake levels and may have exceeded the capacity of the regulatory system to respond. The major variability in lake levels in recent years demonstrates the need for better understanding of the drivers of water level variability towards improving regional water resources management and policy (Gronewold and Rood, 2018).

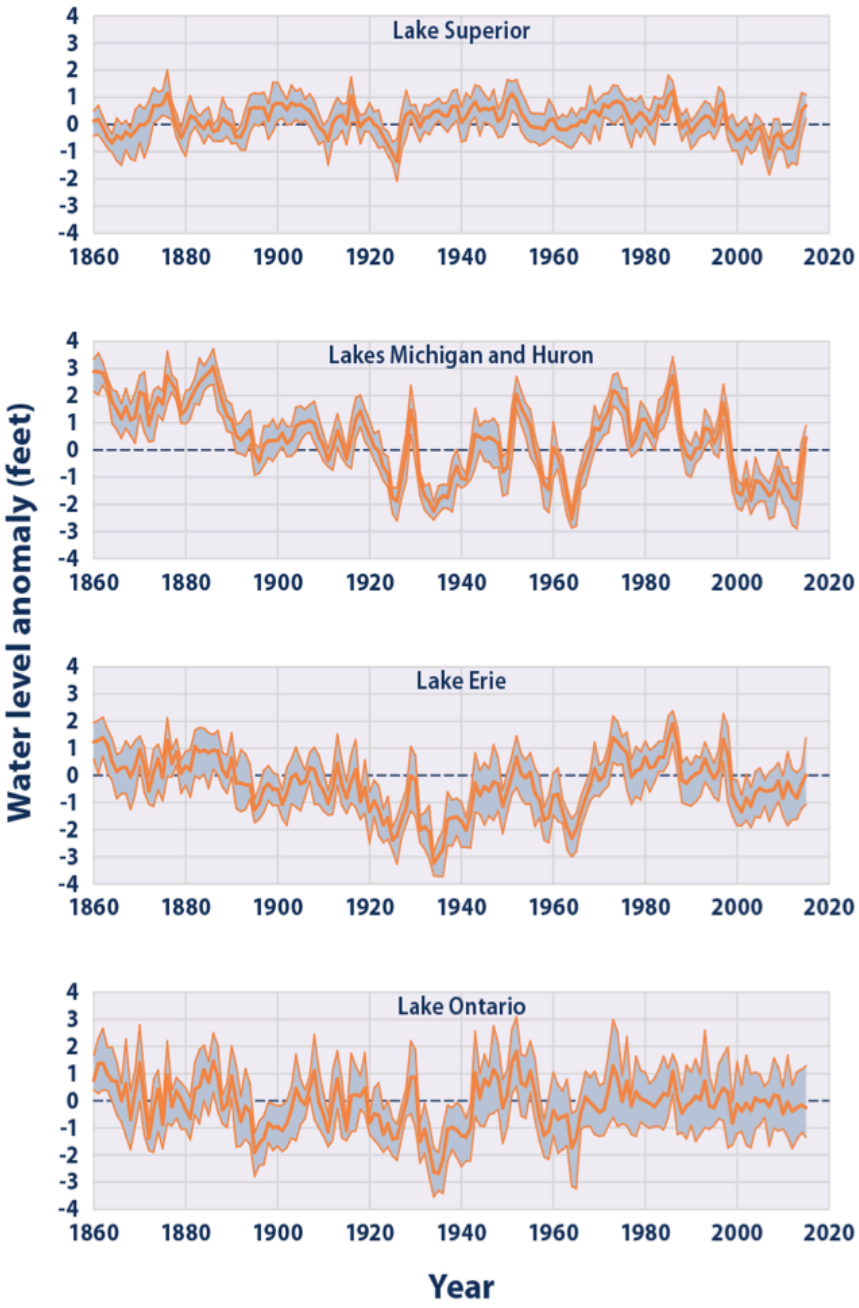


Figure 7. Water levels of the Great Lakes from 1860 to 2015 as an anomaly relative to the 1981-2010 average. The shaded band shows the range of monthly average water levels, and the line in the middle shows the annual average. Choosing a different baseline period would not change the shape of the data over time. Lakes Michigan and Huron are shown together, because they are connected at the same water level. Source: Data from NOAA as reported by https://www.epa.gov/climate-indicators/great-lakes.

Methods of projecting lake levels in the mid to late 21st century have undergone a revolution in recent years. Lofgren et al. (2011) and Lofgren and Rouhana (2016) have shown that evapotranspiration from land (part of the calculation of runoff) was depicted in older models (as used in Angel and Kunkel, 2010; Lofgren et al., 2002; and many others) as extremely sensitive to climate change. We now know that those earlier analyses tended to overestimate the evapotranspiration effects. Results using other methodologies (Milly et al., 2005; MacKay and Seglenieks, 2012; Notaro et al., 2015; Lofgren et al., 2016) have generally projected very modest drops in lake levels and appreciable probability of small rises, in contrast to the large drops in lake level projected by the prior methods.

LAKE LEVELS

Comparison between historical trends in variables related to Great Lakes Basin hydrology and model-predicted results at the time scale of a century have differing levels of agreement, and historical time series often have issues of signal-to-noise ratio (i.e. they show trends, but variability over the decades of record is also highly significant in comparison). Trends in lake surface temperature are quite notable, with interactions between the lake surface temperature and the stability of the lake temperature profile helping to amplify the surface temperature trends. Trends in ice cover are also robust, with large decreases since the beginning of record in 1973, despite some reversals in this trend from some recent cold winters. Precipitation, evaporation, and runoff show more mixed results, with precipitation and evaporation generally increasing, with specific locations as exceptions, and runoff differing significantly among the individual lakes. The trend in Net Basin Supply also differs from lake to lake. Records of lake level over several decades show that trends are small and variability is high. Newer model-based projections of lake level (since 2011) foresee a central tendency toward small drops in lake levels to the end of the 21st century, with appreciable probability of small rises in lake levels, in contrast to the large drops projected using the older, now-defunct methodology.

4. Changes in Great Lakes watershed hydrology

Regional watershed hydrology will be driven by change in climate and land use, as well as by changes in demand. Warmer and wetter conditions will prevail on average, but increasing evaporative demand coupled with potential decreases in summer precipitation will likely lead to increased irrigation demand during the growing season. Continued expansion of urban land use will increase the need for stormwater management. Both agriculture and urban land use will continue to affect water quality in the future.

This section reviews some of the main ways in which climate will affect Great Lakes watershed hydrology and how that may be exacerbated by land use / land cover change occurring throughout the basin. Additionally, more specific impacts that may result from agricultural and urban land use are also reviewed to provide key insights for these dominant human landscape stressors.

4.1 Climate change effects on lake hydrology

Historically, precipitation increases have been relatively well distributed across the year. Future climate projections, however, suggest that precipitation will continue to increase in the winter and spring months. Summer and fall precipitation will be more variable in the near term but tending towards decreases by the end of the century.

Drier summer conditions are most likely under high emission scenarios. Increased winter and spring precipitation will directly increase river discharge in winter and spring months (Cherkauer and Sinha, 2010; Byun et al., 2018).

With less precipitation falling as snow, there is a decrease in flooding associated with spring snow melt, but mean streamflow will still be higher during those months because of greater overall precipitation (i.e., more rain). For larger watersheds this is expected to shift annual peak flows earlier in the season (Byun et al., 2018), while for smaller watersheds the increased frequency and magnitude of storms in the late spring will compete with snow melt as the primary driver of annual peak flow events, potentially shifting some peak flows later in the year (Cherkauer et al., 2018). Flood risk is also projected to increase in the future (Cherkauer and Sinha, 2010; Byun et al., 2018). Water storage in the landscape, as soil moisture, aquifer recharge, and the refilling of wetlands and small lakes will also increase during the winter and spring (Cherkauer et al., 2018; Byun et al., 2018), though water storage as snow will decrease.

Higher summer and fall air temperatures will increase evaporation during the growing season. Coupled with summer precipitation that is increasingly variable and likely lower, summer river flows will be lower than historical observations by the end of the century (Byun et al., 2018). The increased intensity of summer storm events is likely to contribute to an increase in the flashiness, or day-to-day variability, of river discharge (Cherkauer and Sinha, 2010). Increased evaporation during the growing season will also reduce water stored in the landscape, increasing soil moisture deficits in the fall (Byun et al., 2018; Cherkauer et al., 2018). This will increase the difference in water storage between wet and dry seasons. For example, Byun et al. (2018) project that soil moisture storage will decrease by about 8% in September and October by the end of the century under the high emissions scenario. For the same scenario, they project soil moisture storage to increase by around 10% in February and March by the end of the century.

4.2 Land use / land cover change

Land use and land cover influences climate by changing regional temperatures, precipitation, vegetation, and the patterns of thunderstorms (Pielke, 2005). Land use is projected to remain an important contributor to local changes in climate (Sala et al., 2000; Pielke et al., 2002; Pielke, 2005; Mahmood et al., 2010) and often occurs concurrently with hydrologic change (see Lee et al., 2011; Jarsjö et al., 2012, Destouni et al., 2013). Urban areas, in particular, have a disproportionate influence on climate, hydrology, and water quality (Price, 2011).

Table 4 summarizes the current land use and land cover for the Great Lakes Basin. Over 34 million people reside in the Great Lakes Basin, with two-thirds in urban settings (IJC, 2009). These urban areas cover around 10% of the basin, but represent the fastest growing land use type (Wolter et al., 2006, SOLEC, in review). Changes in land cover and land use are difficult to track for the entirety of the Great Lakes Basin due to differences in timing of land cover mapping, map resolution, and classification across the United States and Canada (SOLEC, 2017). For the period 2000 – 2011, the SOLEC (2017) Land Use Change indicator reported a net conversion of only 0.05% for the entire basin, but the majority of that change reflected an increase in developed areas (+0.38%) and a decrease in forest area (-0.5%). Data from a remote sensing study of the U.S. side of the basin (Wolter et al., 2006) reported a 2.5% change in land use from 1992 – 2001, with the greatest increases occurring in low intensity development (+33.5%), road area (+7.5%), and decreases of about -2.3% each in agricultural and forest lands. Increases in urbanization were concentrated in coastal areas of the Great Lakes.

There is strong evidence that forest ecosystems are already responding to climate change in the Great Lakes region (e.g., Iverson et al., 2008; Woodall et al., 2009; Zhu et al., 2012; Fei et al., 2017). In general, evidence suggests that individual tree species are moving northward and westward at 10-15 km per decade, with relatively strong shifts northward in northern hardwood forests around the Great Lakes (Woodall et al., 2009; Fei et al., 2017). However, some studies have also shown some eastern tree species are susceptible to range contraction due to climate change (Zhu et al., 2012; Iverson et al. 2017). Similarly, recent studies examining potential range shifts over a decade in the eastern United States found little evidence of range shifts, despite underlying changes in climatic conditions, raising concerns about range contraction.

One important factor that will influence land use and land cover change, and resulting effects on hydrology, is carbon fertilization. The Free Air Enrichment Studies (FACE) illustrated that elevated CO2 would increase net primary productivity in forests (e.g., Norby et al., 2005; Norby and Zak, 2011). Keenan et al. (2013) find strong increases in water use efficiency, suggesting that as CO2 levels increase, forested ecosystems will use water differently, potentially shifting watershed hydrology. There are important feedbacks between land use, land cover, and hydrologic response in the Great Lakes that are only poorly understood at present.

Policy responses to climate change could also have strong influences on land use change. Stavins (1999), Plantinga et al. (1999), Adams et al. (1999), Sohngen and Mendelsohn (2003), Murray et al. (2005), and recently Fargione et al. (2018) have suggested that implementation of natural climate solutions, including expansion of forests to sequester carbon, are economically feasible at costs comparable to energy sector mitigation options. According to these studies, there are significant opportunities to establish forests throughout the Great Lakes watershed, and policy efforts aimed at mitigating climate change could strongly influence future land use and land cover throughout the region. In general, these changes would involve expansion of forests at the expense of agriculture and grazing land.

4.3 Agricultural watersheds and agricultural impacts

The Fourth National Climate Assessment (USGCRP, 2018; Angel et al., 2018) illustrates key changes in Midwestern climate conditions that will affect crop productivity, including lengthening growing seasons; changes in precipitation patterns; shifts in minimum, maximum, and average temperatures; shifts in humidity levels, etc. These changes are already affecting crop production and are expected to continue shifting in the future. For instance, changes in seasonal precipitation are already affecting farmers in Midwestern states, with planting delays related to spring flooding and excessively wet soil conditions (Bowling et al., 2018). Outflow from subsurface drainage, historically at its peak in winter and spring months, is expected to increase in the future (Cherkauer et al., 2018). This is in part due to increased precipitation during those months, but also due to warming via the decreasing influence of snow and soil frost on infiltration.

Delayed planting puts crops at greater risk under hotter and drier conditions later in the growing season. This increases the demand for irrigation to mitigate crop losses (Bowling et al., 2018). Increased irrigation is already appearing in many Great Lake states. Groundwater is increasingly being used for irrigation throughout the Midwest, and in some cases pumping is lowering groundwater levels (e.g., Cherkauer et al., 2018). There is growing awareness that water storage must increase in the region to capture more of the plentiful winter and spring precipitation, and store it until needed to reduce summer losses. Increased storage on farms distributed across the landscape will have an effect not yet quantified, related to flood risk and water availability, discussed in Section 4.1.

A number of empirical studies have examined the influence of weather and climate on crop yields, focusing on the U.S. Midwest given its global importance. These studies have suggested that climate change could have significant impacts on corn and soybean yields in the Great Lakes region (e.g., Schlenker and Roberts, 2009; Urban et al., 2012; Lobell et al., 2014; Gustafson et al., 2015; Bowling et al., 2018; and Jin et al., 2017). Depending on climate mitigation efforts and adaptation, climate change could reduce crop yields by 10-30% by the middle to latter parts of this century. The largest negative effects will occur in the southern Great Lake states (Urban et al., 2012; Bowling et al., 2018), as maize in particular is increasingly at risk to drought stress (Lobell et al., 2014). Despite potential falling productivity in currently important crops in the region, agriculture is expected to remain in important land use in the Great Lakes region due to adaptation (Haim et al., 2011).

Efforts to adapt with irrigation, adaptation of new varieties, and alternative management approaches can help mitigate some of the yield losses experienced by growers. Climate change will also encourage farmers to adapt their management by switching to new crops, among other approaches (Mendelsohn et al., 1994; Easterling et al., 2000; Deschenes and Greenstone, 2007; Massetti et al., 2016; Mendelsohn and Massetti, 2017). For some areas, this may include double cropping where more than one crop is grown in a field per year, increased use of cover crops, and changes to new mixtures of crops better suited for the future climate (recognizing the large differences in soil productivity across the Great Lakes region). There is evidence that important crops, in particular corn and soybean, will shift northward (e.g., Easterling et al., 2000; Laingen, 2017).

4.4 Urban watersheds and urban impacts on the Great Lakes

Land use impacts on climate are well documented (Mahmood et al., 2010), as are effects of land use / land cover on hydrology (e.g., Mao and Cherkauer, 2009). Interacting effects of climate, land use, and human population are difficult to quantify independently, and the simultaneous effects have rarely been studied. Direct impacts of urban land use on hydrology stem from water diversions. These include massive infrastructure projects such as the Chicago Water Diversion, which in 1900 reversed the flow of the Illinois River to drain to the Mississippi River instead of to Lake Michigan (Annin, 2018), and more modest diversions resulting from shallow groundwater withdrawals, rerouted stormwater runoff, or smaller wastewater systems exported outside catchments (Price, 2010). The Great Lakes Compact, signed in 2008, is designed to protect the basin from further withdrawals, through a set of protocols that define the geographic boundaries and the conditions under which water is withdrawn and then returned (Annin, 2018). Unfortunately, this agreement does not address the potential impacts of climate change on groundwater and surface water quantity and quality.

There is emerging understanding that the hydrologic behavior of urban areas is more complex than was previously known. The dogma that vegetation removal and replacement with impervious surfaces decreases baseflow due to changes in recharge has been challenged by more recent studies that demonstrate both increased and decreased recharge associated with urban areas (Price, 2010). Some effects of urban development are well known: decreased groundwater recharge from impervious surface and soil compaction, rapid transmission of stormwater to waterways, shallow groundwater leakage to stormwater sewers, shallow stormwater withdrawal, and rerouted wastewater. But increased groundwater recharge can result from changes in surface distribution of imported water from irrigation and outdoor water use, infrastructure leakage, stormwater detention in artificial structures, and movement of stormwater to shallow groundwater via storm sewers (Lerner, 2002; Price, 2010). Green infrastructure such as parks, green street corridors, rain gardens, and natural areas, are increasingly being

examined as cost-effective strategies for cities to increase water storage in soil and groundwater, thereby decreasing stormwater runoff (Hopton et al., 2015; Carlson and White, 2017).

Increasing variability in precipitation patterns, especially during early spring when grounds are frozen or when rainfall occurs onto snow, are likely to exacerbate stormwater runoff and flooding events. However, these processes will have variable results on baseflow and groundwater recharge depending on the regional geology, type and status of infrastructure repair, and stormwater and wastewater management practices. Direct effects of climate on baseflow are likely to be highly variable depending on regional conditions. For example, higher summer time temperatures are likely to result in increased convective precipitation and more intense storms. Modeling studies suggest that seasonality of flow regimes, combined with warmer temperatures are likely to reduce base flow (e.g., Choi, et al., 2009). An empirical study in Wisconsin showed that climate change was the dominant driver of baseflow timing, but land use change interacted with climate to alter the magnitude of changes (Juckem et al., 2008). The amount of impervious surface and compacted soil are likely to be strong determinants of those responses (Smakhtin, 2001; Easterling et al., 2000). Vegetation type and distribution have a strong impact on both local and regional hydrology, and land use conversion can either increase or decrease runoff as a result (Mao and Cherkauer, 2009).

4.5 Water quality impacts on the Great Lakes

Urban influences on water quality are strongly linked to hydrology and climate, especially to changing precipitation patterns (IJC, 2009). Globally, increases in climate-mediated precipitation are predicted to result in increased total nitrogen loads to rivers, although much of this is due to agricultural activities rather than urban inputs. Future cross-model mean projections of nitrogen loading for the Great Lakes region show the large regional increases (+21%) for the 2071-2100 period under the high emission scenario (RCP8.5) (Sinha et al., 2017). An additional concern for the Great Lakes lies in loading of dissolved phosphorus from watersheds, with a special concern for its effect on harmful algal blooms and dissolved oxygen concentrations (Scavia et al., 2014; Burlakova et al., 2018). Since the 1990's algae blooms, benthic algae, and extensive hypoxia zones have re-emerged as problems in Lake Erie (Scavia et al. 2014), and have been linked to phosphorus loading from agricultural sectors. SPARROW model output for the U.S. tributaries of the Great Lakes have identified sources of phosphorus to the Great Lakes from a wide variety of sources including point sources (industrial, commercial, and sewage), confined and unconfined manure, farm fertilizer, nonpoint sources from urban and developed land, as well as forest and wetland areas (Robertson and Saad, 2011; ELPC, 2018). Across the Great Lakes, inputs from urban and agricultural sources were similar for all lakes except Lake Superior, which supports little agricultural activity. Around 50% of phosphorus inputs were derived from point sources and urban sources for all Great Lakes except Lake Superior. Manure was an important source of phosphorus in Lakes Michigan and Ontario (Robertson and Saad, 2015). Sources of nitrogen were mainly attributed to agricultural practices and atmospheric deposition. From the standpoint of climate change impacts, nutrient delivery via tributaries is the dominant input to the Great Lakes, thus climate-driven patterns influencing flow regimes are likely to have a large impact on future nutrient delivery to the Great Lakes (Robertson and Saad, 2015). Large storms are likely to increase the incidence of sewage bypass in urban areas (i.e., combined sewer overflows) and flooding of manure management systems, thereby increasing the input of phosphorus into the Great Lakes.

URBAN ISSUES IN THE GREAT LAKES REGION

In the Midwest and Great Lakes regions, high weather variability, high-intensity urban development, and undersized infrastructure yield severe and accelerating vulnerability to urban areas as a result of such extreme events (Borden et al., 2007; Wilson et al., 2010; Pryor et al. 2014, Kristovich et al. [in review]). Interaction of the Great Lakes with coastal urban environments modify the lake breeze and shifts the urban heat island inwards (Sharma et al., 2017). Heat waves and poor air quality often co-occur because they are both associated with air stagnation (Schnell and Prather 2017; Sharma et al., 2016). The combination of high heat and poor air quality produces severe adverse impacts on public health, including considerable numbers of deaths during heat waves (Changnon et al., 1996; Palecki et al., 2001; Anderson and Bell, 2011). Increasing urban temperature and development of hot-spots adversely affect vulnerable low-income urban communities (Sharma et al., 2018). Projected increases in extremely warm and hot days, described previously, indicates that these risks are increasing in Great Lakes cites (Luber and McGeehin, 2008). Green infrastructure is likely to reduce urban stress in the Great Lakes region. However, an aggressive implementation of an adaptive strategy may reduce lake breeze and vertical mixing during daytime and could lead to stagnation of air near the surface causing poor air quality (Sharma et al., 2016). Thus, green infrastructure such as green and cool rooftops can provide relief for hot Great Lakes cities, but should be sited carefully (https://theconversation.com/green-and-cool-roofs-provide-relief-for-hot-cities-but-should-be-sited-carefully-60766).

Increased precipitation in extreme storms is also expected to present particular hazards to cities. Many Great Lakes cities experience frequent flooding from intense, localized storms (CNT, 2013; Winters et al., 2015). Under-resourced communities suffer a disproportionate burden of storm impacts, owing to the confluence of low property values and lack of infrastructure in low-lying flood-prone areas (Wilson et al. 2010, CNT 2013). The projected increase in extreme precipitation events in this region, as documented previously, is likely to exacerbate these problems, leading to increased flooding in the winter and early spring, as well as increased flooding from summer thunderstorms. These effects are already being seen, for example in extreme winter rain events and associated flooding in 2017 and 2018 (e.g., https://www.nbcchicago.com/news/local/flood-photos-chicago-south-suburbs-474717273.html, https://www.npr.org/sections/thetwo-way/2018/02/22/587881723/widespread-flooding-brings-misery-to-midwest).

5. Impacts on ecology of the Great Lakes and the region

The ecology of the Great Lakes region is already being affected by climate change, and these impacts are likely to strengthen in the future as the climate in the region continues to change. This section explores the understanding of these current and potential impacts.

5.1 Mixing and oxygenation

As mentioned in section 3.1, since fresh water has its maximum density at 4°C, the water column becomes unstable when surface water that was previously at a temperature farther away from that temperature moves closer toward it (e.g. after the surface water has reached its maximum temperature for the year and starts cooling, it becomes denser than the water below it and will start mixing). The water column typically passes through the 4°C threshold and mixes completely twice each year, on the way up in the spring and on the way down in the fall (they are "dimictic"). The spring overturning has become earlier with warming and the fall overturning later. Since the spring overturning represents the initiation of a stable configuration of the water column with the warmest water on top, inhibiting deep mixing as time goes on and enhancing the warming at the surface, this is noted as a mechanism for summer surface water temperatures to be increasing at a greater rate than air temperatures over adjacent land areas (Austin and Colman 2007). Animations available at https://coastwatch.glerl.noaa.gov show that there are parts of southern Lake Michigan and of Lake Ontario whose surface temperature stayed above 4°C during the winters of 2011-12 and 2016-17, so their water columns presumably did not mix fully during those years.

That vertical mixing brings nutrients up from the sediment at the bottom of the lake, and oxygen down from the surface, so it is crucial for ecosystems. In addition to altering the seasonal character of vertical mixing, the observed (and expected continuing) trend toward rainfall being concentrated in very heavy events is likely to increase the amount of nutrients reaching the lakes. Scavia et al. (2014) and Bosch et al. (2014) show this as one of the influences leading to increased nutrient load into the lakes, along with practices surrounding agricultural fertilizer application and drainage. This is particularly serious in the central basin of Lake Erie, because the water depth is such that not much mixing occurs to the bottom, yet the mass of water below the thermocline is small enough that decomposition of organic matter in the sediment can consume the oxygen within that layer. Michalak et al. (2013) document a major algal bloom in western Lake Erie that made Toledo, Ohio's municipal water unsafe to drink for weeks. This occurred following sudden increased water flow in tributary rivers in that area that transported a heavy load of nutrients, in particular from the Maumee River. Such events could become more likely given the intermittent, but very heavy rainfall events expected under a warming climate.

5.2 Biodiversity and invasive species

Over geologic time-scales, the Earth's climate has been the single most important factor controlling the distribution of the world's species and the biodiversity of species in any given location (Parmesan and Yohe 2003). Climate sets the physiological limits of species range distributions, controls the co-evolutionary processes that cause species to become mutually dependent, and influences the spread and interactions among species that control community membership. Therefore, climate change is predicted to have significant impacts on the biodiversity of all ecosystems, with these impacts occurring on short time-scales matching the timing of changes projected to occur through the current century.

The ultimate impact of climate change on biodiversity in the Great Lake ecosystem will depend on how the various components of climate change (warming, increased CO2 concentrations, changes in water acidity and oxygen levels, altered frequency and intensity of storms, etc.) collectively impact four factors that regulate biodiversity: (1) invasion rates by new, non-native species, (2) replacement of widespread or abundant species by those that are presently uncommon or rare, (3) emergence or proliferation of new pests and disease that might impact established species populations, and (4) extinction rates of the existing established species assemblage (Figure 8).

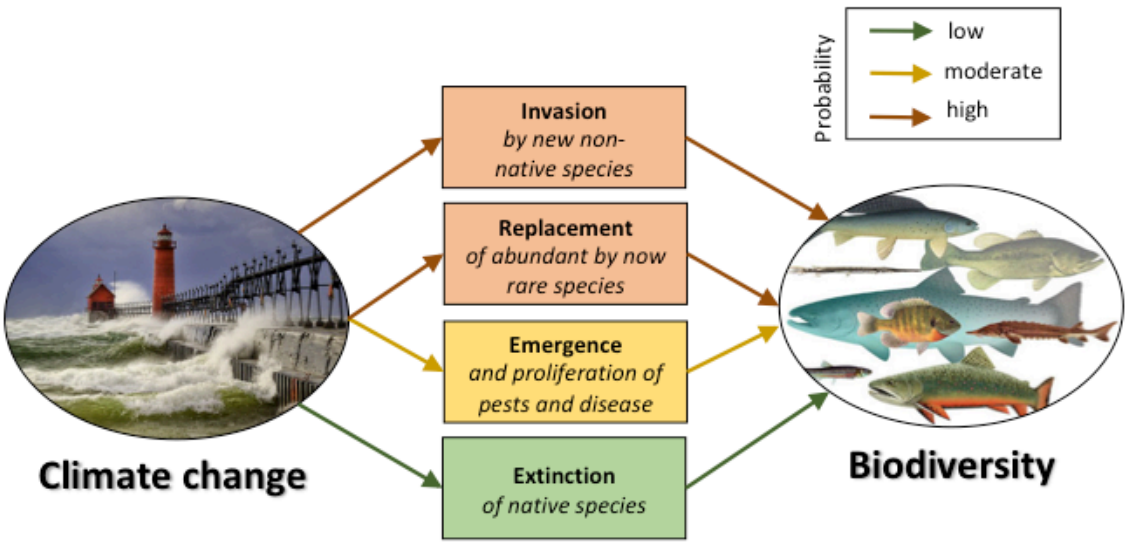


Figure 8. The impact of climate change on biodiversity in the Great Lakes will depend on how climate change impacts four factors that contribute to diversity: (1) invasion by new, non-native species, (2) replacement of currently dominant species by those that are now rare (i.e. species turnover), (3) the emergence and proliferation of pest and disease species that impact of native populations, and (4) extinction of currently native species. These are ranked from their highest to lowest probability or risk.

The greatest effects of climate change are expected to occur from the redistribution of flora and fauna that lead to the introduction of non-native species (Pecl et al., 2017). There are already well-documented examples of climate change altering the range distributions of species, leading to introduction of novel species into ecosystems. Indeed, 87% of all species monitored have displayed range shifts as they have migrated towards the poles at rates exceeding 3.7 miles (6 km) per decade (Parmesan and Yohe, 2003).

Within the Great Lakes watershed, one of the best examples of range shifts altering biological communities comes from surveys of sport and baitfish populations. The range boundaries of numerous sportfish have shifted northward at a rate of 8 to 11 miles (12.9 to 17.5 km) per decade over the past 30 years, which has led to widespread introductions of formerly "southern" warm-water fish species into northern latitude lakes (Alofs et al., 2013).

There is also good evidence that climate change has initiated species 'turnover' as formerly rare or uncommon species have benefited from climate change and begun to proliferate (Collingsworth et al., 2017). For example, smallmouth bass (Micropterus dolomieu) have historically been limited in their northern distribution by the length of the ice-free growing season and overwinter survival of their young-of-the-year (yoy). As the ice-free season has increased, and as warming has improved young of year survival, populations of smallmouth bass have proliferated in lakes that they currently occupy, and expanded to waterbodies throughout the Great Lakes watershed they did not formerly occupy (Alofs et al., 2013; Alofs and Jackson, 2014). Because smallmouth bass are voracious predators, their expansion has reduced more than 25,000 populations of northern redbelly dace (Phoxinus eos), finescale dace (Phoxinus neogaeus), fathead minnow (Pimephales promelas), and pearl dace (Margariscus margarita) throughout lakes in Ontario (Jackson and Mandrak, 2002).

In Lake Superior, white perch (Morone americana) and alewife (Alosa pseudoharengus) have historically been rare, but are expected to expand their distributions with continued climate warming (Bronte et al., 2005), likely

owing to reduced overwinter mortality (Hook et al., 2007). The invasive round goby (Neogobius melanostomus) is also expected to gain more beneficial habitat with continued warming across the Great Lakes (Kornis et al., 2012), as may the flathead catfish (Pylodictis oliverus) (Fuller and Whelan, 2018).

Climate change is also likely to exacerbate the emergence and proliferation of pest and disease species. For example, bioenergetics modeling has demonstrated how sea lamprey (Petromyzon marinus) have benefitted from the warming of Lake Superior since 1979 by growing larger and more fecund (Cline et al., 2013). These trends are problematic because invasive sea lamprey have already had large negative effects on fisheries by parasitizing and killing recreationally important piscivores and commercially important lake whitefish (Coregonus clupeaformis) as adults (Bence et al., 2003). Larger more fecund individuals are likely to inflict even higher mortality rates on their hosts.

Patz et al. (2008) suggested the prevalence of water-born pathogens will increase with climate change. They showed that climate change models predict an increase of extreme precipitation events by 10% to 40% in southern Wisconsin, which will result in a 50% to 120% increase in the frequency of combined sewer overflows into Lake Michigan. Those overflows are projected to introduce hundreds of new species of pathogenic bacteria, viruses, and protozoa.

Although climate change will undoubtedly affect Great Lakes biodiversity by promoting invasion by non-native species, replacement of common by formerly rare species, and the proliferation of pests and disease, the risk of extinctions caused directly by climate change is uncertain. Even while climate change is often touted as a great risk to biodiversity (Thomas et al., 2004), few empirical examples of extinctions have ever been directly linked to climate change (the first was reported by Gynther et al., 2016). Nor have any extinctions of native species that we know of have been directly attributed to climate change in the Great Lakes.

While extinctions caused directly by climate change are likely to be rare, the potential of extinctions caused indirectly through climate change's impact on invasive species, species replacement, or the proliferation of new pests and disease are possible. However, the importance of these indirect effects is currently controversial, and has a high degree of uncertainty. For example, while it has historically been assumed that invasive species are a leading cause of native species extinction (Wilcove et al., 1998), recent evidence suggests that invasive species rarely cause extinctions (Gurevitch and Padilla, 2004) and, in fact, non-native introductions often cause biodiversity to increase as invasion rates outpace extinction rates (Sax and Gaines, 2003; Dornelas et al., 2014). Therefore, the cumulative impact of climate change on extinctions (direct and indirect effects) is presently unknown.

5.3 Nutrient loading and algal blooms

Harmful algal blooms (HABs) are increasing in frequency and severity worldwide. Many of the variables that control the frequency and severity of HABs – such as nutrient loading, water temperature, and stratification -- are directly influenced by climate change (Wells et al. 2015). As such, climate change is expected to alter the frequency and severity of HABs. Increased nutrient loading caused by agricultural fertilizers, urban wastewater, and soil erosion is the primary cause of HABs in water bodies throughout the world (Heisler et al. 2008), including in the Great Lakes (Watson et al., 2016). Nutrient loading to Great Lakes coastal zones is generally expected to increase as a result of climate change, mostly due to a greater frequency of large precipitation events that increase runoff from agricultural landscapes in the surrounding watersheds. For example, Cousino et al. (2015) incorporated

predictions from recent climate change models into a Soil & Water Assessment Tool (SWAT model) of the Maumee River to predict the effects of climate change on water, sediment, and nutrient yields. The Maumee River, which is a dominant source of nutrients to the western basin of Lake Erie that experiences frequent HABs, is expected to experience more extreme precipitation and runoff events in the future. Unless nutrient and sediment loads are offset by improved land management practices (Scavia et al., 2017), models predict that climate change will increase eutrophication of western Lake Erie with greater nutrient loading by the Maumee River.

There is some evidence that extreme climatic events have already contributed to HAB formation in the western basin of Lake Erie (Figure 9). Michalak et al. (2013) studied the record-setting 2011 algal bloom in Lake Erie, which was caused by the toxin-forming cyanobacteria Microcystis (July and August) and Anabaena (September and October). Although agricultural runoff is the normal cause of the routine blooms that form in the basin, several climactic anomalies contributed to the 2011 event being unusually large. In particular, a May 2011 storm caused the Maumee River to reach the 99.8th percentile for its daily discharge, leading to an abnormally high amount of nutrient runoff. Then, after the bloom started, weather conditions were unusually conducive for growth – with "warm and quiescent conditions" for 62% of the time after bloom onset, relative to 35%-36% in other years. This study suggests that the increasing frequency of large precipitation events in the Great Lakes region and general warming patterns could increase the probability of particularly large or severe blooms.

Figure 9. In 2011, Lake Erie experienced the largest harmful algal bloom in its recorded history, with a peak intensity over three times greater than any previously observed bloom. Climate change is expected to increase the frequency of these large algal blooms
Source: MERIS/ ESA Satellite photo, processed by NOAA/NOS/NCCOS; https://www.canr.msu.edu/news/lake_erie_harmful_algae_bloom_threatens_drinking_water_supplies.

In addition to nutrient loadings, higher water temperatures are known to preferentially favor growth by certain types of bloom-forming algae and cyanobacteria (O'Neil et al., 2012). At water temperatures above 20°C, the growth rates of freshwater eukaryotic phytoplankton stabilize or decrease, while growth rates of many bloom-forming cyanobacteria increase (e.g., Microcystis, Anabaena, and Cylindrospermopsis). Warming water temperatures may have been responsible for an unprecedented algal bloom in Lake Superior that spread across 50 miles of Lake Superior shoreline in 2018, from Superior, WI to the Apostle Islands (https://www.nytimes.com/2018/08/29/science/lake-superior-algae-toxic.html)

Increased water temperature can also increase the frequency of toxin production by bloom-forming species. For example, Davis et al. (2009) found that enhanced temperatures yielded significantly increased growth rates of toxic Microcystis in 83% of the experiments conducted, but did so for non-toxic Microcystis in only 33% of experiments. This suggests that elevated water temperatures may yield more toxic blooms.

Climate change is also increasing the duration and intensity of lake stratification (Kraemer et al., 2015), which is expected to promote HABs. Lehman (2002), for example, used nested physical and biological models to simulate future stratification and mixing conditions for the Great Lakes that are projected under climate change through 2090. Those models predicted elevated mixed layer and bottom temperatures in all five Great Lakes by as much as 5 °C this century, with longer duration of thermal stratification, stronger stability of stratification, and deeper daily mixing depths during peak thermal stratification. Many HAB species uniquely adapted to exploit stratified conditions. For example, most bloom-forming cyanobacteria contain gas vesicles that provide buoyancy, enabling them to form dense surface blooms in stratified waters where they can take advantage of high levels of irradiance to optimize photosynthesis (Paerl and Paul, 2012). Many surface-dwelling cyanobacteria also contain photoprotective accessory pigments (e.g. carotenoids) and UV-absorbing compounds (mycosporine-like amino acids [MAAs], scytonemin) that ensure long-term survival under high irradiance conditions, while suppressing non-buoyant species through competition for light (Paerl and Paul, 2012).

5.4 Fish

Fish species in the Great Lakes region will be directly affected by climate change phenomena including temperature increases, increases in storm intensity and frequency, and shifting seasonal patterns. Many Great Lakes fishes are influenced by water temperature, for example, which contributes to distinct cold, cool, and warm-water assemblages throughout the region (e.g., Magnuson et al., 1997; Wehrly et al., 2003). Additionally, shifting seasonal patterns of precipitation and ice formation can similarly affect species whose behavior is cued to those events. Besides these direct changes, effects of climate change phenomena on fish habitats will further impact species. Changing precipitation patterns and storm impact hydrology will impact drainage patterns, connectivity, water levels, and the extent and quality of littoral habitat. Increases in water temperature, along with earlier warming in spring, will increase the depth and duration of stratification. This, in turn, will promote depletion of upper oxygenated layers of water, resulting in more widespread and profound periods of bottom anoxia (Trumpickas et al., 2009; Collingsworth et al., 2017). Together, these changing environmental drivers will have multiple effects on Great Lakes fishes by changing 1) geographic ranges, 2) overall system productivity, 3) species-specific productivity, 4) spatial arrangement within a system due to changing habitat suitability (Shuter et al., 2012; Poesch et al., 2016; Lynch et al., 2016) and 5) changes in physiological state and performance (Whitney et al. 2016).

Many modeling studies have been conducted predicting impacts of climate change on fish (e.g., Jackson & Mandrak, 2002; Sharma et al., 2007; Sharma and Jackson, 2008; Herb et al., 2016; Van Zuiden et al., 2016), with

many of these focused on coldwater fish species or assemblages. Fewer studies have reported empirical observations of climate change impacts. Such studies (reviewed by Comte et al., 2013; Lynch et al., 2016) have documented shifts in geographic range, changes in demographics (abundance, growth, recruitment), increased occurrence of diseases, phenological shifts (earlier migration, spawning), extirpation (especially of coldwater species), and hybridization resulting from novel species interactions (Lynch et al., 2016; Collingsworth et al., 2017). Comte et al. (2013) compared predicted versus observed responses and found that in general, the observed effects of climate change are much greater (mean of 8x) than those derived from model predictions. Overall positive impacts from empirical observations were found on Cyprinidae, Percidae, Ictaluridae, and Salmonidae; although Salmonidae showed more mixed effects than the other families. In general, predicted studies reported a high proportion of negative effects for coldwater species. In Lake Superior, the coldwater fish assemblage was predicted to experience little change, with the exception of the lake siscowet (a variety of lake trout [Salvelinus namaycush]), which have extreme cold thermal tolerances (Magnuson et al. 1997).

Range expansions have been among the most commonly observed changes that indicate climate change impacts on fish. At mid-latitudes (40°N to 50°N), warm- and coolwater species have exhibited increased presence, abundance, and distribution (Johnson and Evans, 1990; Alofs et al., 2014). Within the Great Lakes Basin in Ontario, range expansions have been documented for game fish (mainly bluegill [Lepomis macrochirus]), largemouth bass [Micropterus salmoides], smallmouth bass [Micropterus dolomieu], and brown bullhead [Ameiurus nebulosus]), which have migrated poleward at the rate of 13 km per decade over a recent 30 year period. In contrast, there were no statistically significant changes observed in the range of preyfish species, although the trend was towards range contraction (Alofs et al., 2014). Studies assessing factors that control establishment of novel species suggest that abiotic factors (habitat, water temperature) are the primary drivers at regional scales, but that biotic factors are more important on a lake by lake basis (Alofs and Jackson, 2015).

Many studies have predicted northward expansion of warmwater species (e.g., Jackson and Mandrak, 2002; Chu et al., 2011; Sharma et al., 2007, Van Zuiden et al., 2016). As geographic ranges expand, community composition is expected to be altered, with greater diversity expected as cool and warm water species invade cold water habitats. In addition to altering predator-prey interactions as a result of these novel species interactions, Biwas et al. (2017) predict an increase in species richness in Ontario lakes of 60-81% by the end of the century, along with changes in the functional traits of the fish community. These include changes in the average thermal guild of species present, smaller body length and weight, lower fecundity, and shorter trophic breadth by 2070 under both a business as usual and best-case emission scenario. Under the best-case emission scenario, 10-40% of Ontario lakes are expected to be impacted by major shifts in community composition. Species that will be affected include lake trout, northern pike (Esox lucius), walleye (Sander vitreus), whitefish (Coregonus clupeaformis) and yellow perch (Perca flavescens). Jackson and Mandrak (2002) predict that range expansion of smallmouth bass will be extremely detrimental to the populations of forage fish; a pattern confirmed by Vander Zanden et al. (2004) and Alofs et al. (2014). This pattern was also confirmed by Robillard and Fox (2006), who reported declines in walleye relative abundance and increases in relative abundance of smallmouth bass in conjunction with decreases in phosphorus concentrations, increased water clarity, and increased water temperature. The later study highlights the difficulty of isolating the impact of climate change versus other environmental stressors such as land use change, which can lead to nutrient loading and the presence of invasive species.

In addition to range expansion and community realignment, climate change has been shown to influence recruitment and spawning behavior, with both "winner" and "loser" species throughout the basin and with some results varying by region. For example, increased temperatures and altered aquatic conditions have facilitated increased recruitment and abundance for some warmwater species (e.g., black basses [Robillard and Fox, 2006]), with increased temperature contributing to declines in cisco (Coregonus artedi) abundance in Minnesota glacial lakes (Jacobson et al., 2012). In Lake Michigan near Milwaukee, yellow perch have been observed to be spawning earlier, by 6.2 days per decade (for the period 1988-2012), while in Green Bay, earlier spawning occurs by 1.8 d/decade (1983-2016; Lyons et al., 2015). In Lake Erie, the timing of yellow perch spawning has not changed despite shorter, warmer winters; however, females are producing smaller eggs that both hatch at lower rates and produce smaller larvae than females exposed to long winters (Farmer et al., 2015). This effect may be explained by shifts in the peak of zooplankton production, a key food for yellow perch larvae. However, there is some evidence that increased river discharge and associated turbidity plumes in Lake Erie may benefit larval yellow perch (reviewed by Collingsworth et al., 2017). Trends for lake trout spawning in Lakes Superior and Michigan are unclear. Lyons et al. (2015) speculate that spring spawning species are likely to be more strongly affected than fall spawning species due to the high variability in water temperature changes during spring, compared to fall. In some Minnesota lakes, walleye are also spawning earlier, in conjunction with earlier ice out patterns (Schneider et al., 2010). In Lake Erie, greater variability in spring warming has been shown to be associated with more variability in spring spawning species such as walleye, and the same pattern was observed for summer spawning smallmouth bass in Lake Opeongo in Ontario. Furthermore, increased summer water temperatures were associated with greater growth rates in walleye (Shuter et al., 2002). These authors predict that fish species that are most sensitive to winter conditions (e.g., alewife [Alosa pseudoharengus]) could be expected to be most sensitive to warming climate in the region, due to the prevalence of winter warming that has characterized the shifting climate patterns

In addition to observed and predicted changes in phenology, simulations of fish growth using bioenergetics models for yellow perch and lake whitefish under different climate scenarios predict that growth rates will decrease more for yellow perch than lake whitefish (Kao et al., 2015). This study also concluded that prey availability may offset the effects of climate change in terms of regulating fish growth rates. This finding provides a caution that temperature tolerance is not the only consideration when predicting effects of climate change on fish.

In conjunction with climate change impacts, the Great Lakes fisheries are heavily impacted by the presence of nonnative invasive species such as the quagga mussels (Dreissena bugensis) and zebra mussels (Dreissena polymorpha), which have dramatically influenced nutrient dynamics and the food web in general (Karatayevet al., 2015; special issue edited by Burlakova et al., 2018). In Lake Erie, in particular, dissolved phosphorus concentrations have increased, and harmful algal blooms and water column anoxia are prevalent, especially in the western and central basins (Scavia et al., 2014). In Lakes Michigan, Huron, and Ontario, nearshore benthic algal production is of special concern, especially for residents of the coastal areas; but offshore, declining phosphorus concentrations and productivity threaten the collapse of the food web (Bunnell et al., 2014; Dove and Chapra, 2015; Barbiero et al., 2018). The importance of water temperature as a key driver of fish distributions was recently highlighted in a study that assessed the major environmental factors explaining distributions of individual fish species in coastal areas of the Great Lakes. In the northern ecoprovince of the Great Lake, an analysis of the main drivers explaining fish presence / absence in coastal areas identified cumulative degree days as the most consistent predictor in models of 12 out of 13 fish species (Kovalenko et al., 2018). In the southern ecoprovince of the Great Lakes, primary drivers were related to water quality and physical habitat factors associated with

habitat structure. The confounding effects of climate change and further land use change (especially in the coastal zone) have not yet been addressed in the context of these issues. Future studies are encouraged to incorporate an ecosystem approach, account for the interaction of multiple, interacting stressors, and to consider the effects of predator-prey interactions as well as availability of prey (Collingsworth et al., 2017).

5.5 Wildlife

Wildlife in the Great Lakes region includes many species of mammals, birds, amphibians, reptiles, and macroinvertebrates. Due in large part to warming air temperatures, but also due to changes in types and patterns in precipitation, soil moisture, and the specific physiology of different organisms (Inkley et al., 2004), geographic ranges of many Great Lakes wildlife species are generally expected to shift northward (Gitay et al., 2002). This broad trend, however, will vary due to local conditions including changes in ice cover and regional precipitation. Additionally, the ability of wildlife to adapt to changing climate will be exacerbated by habitat loss, habitat fragmentation, competition from invasive species, threats from new and emerging diseases, and altered ecological processes (Hoving et al., 2013; Merila and Hendry, 2014). To aid efforts to proactively manage or mitigate for those changes, many attempts have been made to anticipate the vulnerability of key wildlife species to changes in climate, or describe how species distributions may change throughout the Great Lakes region and nationally in the U.S. and Canada (e.g., Frelich and Reich, 2009; Hellman et al., 2010; Hoving et al., 2013; Lawler et al., 2013; Culp et al., 2017). Due to uncertainties in climate change impacts on wildlife habitats and in how those changes could lead to changes in wildlife communities, it is challenging to fully anticipate how individual species may respond to changes in climate. Here, we provide a broad overview of current understanding of how climate has or will affect select wildlife species in the Great Lakes region, with the goals of emphasizing how different groups of taxa may be vulnerable, and to highlight some of the complex mechanism by which species and communities may be affected.

Mammals

Currently, nearly half of the 80 species of native Great Lakes mammals occur at either their southern or northern distributional limits (Kurta, 2017; Myers et al., 2009). This is due in part to the transition that exists between boreal forests in portions of the northern Great Lakes region with systems more common in southern regions like eastern oak hickory woodland, oak savannas, and prairies. In a recent study focused on distributions of 9 common woodland rodent species in Michigan, several species with ranges centered south of the state (white-footed mouse [Peromyscus leucopus], eastern chipmunk [Tamias striatus], southern flying squirrel [Glaucomys volans], common opossum [Didelphis virginiana] were found to have expanded northward into Michigan, while species with northern ranges (woodland deer mice [Peromyscus maniculatus gracilis], southern red-backed vole [Myodes gapperi], woodland jumping mouse [Napaeozapus insignis], least chipmunk [Tamias minimus], northern flying squirrel [Glaucomys sabrinus]) showed range declines in the state (Myers et al., 2009). The authors of this study acknowledge that regeneration of forests and changes in human population may be partially responsible for observed distributional changes, but they assert that warming temperatures are likely the leading factor due to the co-occurring increase in multiple species with historically southern-centered ranges and a decrease in their northern counterparts. In some cases, consequences of range changes are known to have greater impacts than just species replacement. A focused investigation of the white-footed mouse attempted to predict its range expansion in Quebec through the year 2050 (Roy-Dufresene et al., 2013). The white-footed mouse is a carrier of Borrelia burgdorferi, the known pathogen for Lyme disease. The study concluded that warmer, shorter winters will allow the mice to colonize new areas, including southern Quebec, and this is likely to have public health impacts in northern regions that have not currently been exposed to Lyme disease.

Large mammals are also being affected in the Great Lakes region. In Ontario, changes in forest type resulting from changes in climate are expected to affect wildlife species with larger body sizes more substantially than species with smaller body sizes (Thompson et al., 1998). Moose (Alces alces) may be especially vulnerable to climate change. In Minnesota and other part of their range, moose populations have declined precipitously, resulting in an elimination of the moose hunting season in some parts of Minnesota. Changes in climate will affect moose directly; their ability to thermo-regulate in both winter and summer may change with changes in air temperature and precipitation (Rempel et al., 2011). Hoy et al. (2018) have shown a decrease in moose size on Isle Royale, Michigan that they attribute to warming winter temperatures. Compounding these effects, changes in climate will have indirect effects on moose. Preferred habitat and available browse may change with changes in forest cover (e.g., Thompson et al., 1998). Additionally, white-tailed deer (Odocoileus virginianus) are expected to expand northward into habitats historically dominated by moose. White-tailed deer carry the parasite Paralaphostrongylus tenuis which is fatal to moose (Thompson et al., 1998; Murray et al., 2006). Parasites, particularly ticks, are surviving in greater number and have been found to provide yet another stress factor for moose. Finally, increased mortality from wolves may be an additional factor leading to declines in moose populations, and evidence for how changing climate is altering behavior of wolves and increasing mortality of moose has been described on Isle Royale (Post et al., 1999).

Dynamics among Isle Royale grey wolves (Canis lupis) and moose have been studied extensively since 1959 when wolves colonized the island. Pack size of wolves increases with snow depth to increase hunting efficiency, leading to more moose killed by wolf packs per day on the island. These increased kills include more calves and old moose, with kills of old moose being further facilitated by deeper snows (Post et al., 1999). Deeper snows are a consequence of more lake effect snowfall that occurs with an absence of ice cover throughout the Great Lakes, a trend that has been observed around Lake Superior and that is expected to continue in the region (GLISA, 2018). In Ontario, a recent modeling effort attempted to predict moose population dynamics in Ontario through mid-century (Rempel et al., 2011) by accounting for some of the direct and indirect effects of climate change influences on moose, including greater heat stress and parasite loads, reductions in habitat carrying capacity, and more predation by wolves under the A2 climate scenario. All models predicted a decline of moose density at the southern limits of the Ontario range and an increase in density at northern extents.

Birds

Coastal marshes of the lower Great Lakes are among the most biologically significant wetland types in the Great Lakes region, in part due to their role as habitat for staging, nesting, and wintering waterfowl (Hagy et al., 2014) and as stopover sites for migratory birds (Ewart et al., 2012). In coastal marshes of Lake Erie and Ontario, researchers characterized the degree to which fluctuating water levels and associated changes in vegetation affected marsh bird communities (Chin et al., 2014). They found that an index characterizing integrity of bird communities decreased with decreasing water levels. In Lake Erie, the reduced index resulted from a loss of specialist bird species, which include obligate marsh-nesting birds. These findings followed those of an earlier study which showed that habitat suitability for American bittern (Botaurus lentiginosus), American coot (Fulica americana), black tern (Chlidonias niger), least bittern (Ixobrychus exilis), marsh wren (Cistothorus palustris), pied-billed grebe (Podilymbus podiceps), sora (Porzana carolina), swamp sparrow (Melospiza georgiana), and Virginia rail (Rallus limicola) decreased with decreasing water levels in Lakes Erie and Huron-Michigan (Timmermans et al., 2008), in part because marsh bird species tend to avoid dry patches of marsh (e.g., Manci and Rusch, 1988). While expected changes in lake levels described previously in this report include only modest drops overall (e.g., Lofgren et al., 2016), impacts of potential decreases will vary around the basin due to lake bathymetry, unique characteristics of the shoreline, and

other regional influences. This may yield some coastal marsh habitats and their bird communities vulnerable to water level changes that may occur with changing climate.

Lower water levels and higher summer water temperatures are also affecting some Great Lakes birds by encouraging spread of disease. Recent deaths of fish eating birds within the Great Lakes region including red-breasted mergansers (Mergus serrator), ring-billed gulls (Larus delawarensis), and common loons (Gavia immer) have been attributed to the birds ingesting fish infected with a type of avian botulism, Clostridium botulinum (Culligan et al., 2002; Michigan SeaGrant, 2018). While botulism has long been present in the Great Lakes region, outbreaks are occurring more frequently, with researchers attributing those increases to changes in environmental conditions that will be exacerbated by climate change. Lafrancois et al. (2011) described the increased frequency of botulism outbreaks in Lake Michigan from 1963 to 2008 and showed that the outbreaks were related to higher summer water temperatures and lower water levels. They suggested that the frequency and magnitude of outbreaks should increase through the coming century and they called for more comprehensive monitoring of bird communities in response.

5.6 Coastal ecosystems

Like other coastal regions around the world, human activities are concentrated near the ~16,000 km of coastline in the Laurentian Great Lakes. These low-lying areas are particularly vulnerable to the effects of climate change, especially with respect to effects of intense storms and precipitation regimes that influence water level regimes (see Coastal Processes Section below). Water level interacts with geology to determine the extent and type of structural features at the shoreline (e.g., beaches, dunes, barriers, wetlands, and bluffs). Each of these structural features has a particular set of vulnerabilities associated with effects of changing climate as a result of changes in water level regimes, storm patterns and precipitation, ice cover and temperature regimes. These climate stressors and vulnerabilities of coastal ecosystems were reviewed by Mackey (2012).

Due to the long history of concentrated human activity in coastal areas of the Great Lakes, many of the larger ports and estuaries are highly disturbed 43 such sites have received designations as "Areas of Concern" (https://www.epa.gov/great-lakes-aocs) due to degradation of beneficial uses associated with physical, chemical or biological features. As of 2018, restorations have been completed for five sites and are ongoing for a similar number. It is unclear the extent to which climate change is a consideration in these restorations.

Among the coastal ecosystem types, wetlands have received the greatest attention, due largely to their importance as productivity and biodiversity "hotspots" (Cardinali et al., 1998; Vandeboncoeur et al., 2011; fish: Jude and Pappas, 1992; Trebitz and Hoffman, 2015; wetland vegetation: Wilcox, 1995, Lougheed et al., 2001; algae: McNair and Chow-Fraser, 2003; Reavie et al., 2007; birds, waterfowl, amphibians: Timmermans et al., 2008; amphibians: Houlahan and Findlay, 2003; functional richness and traits: Kovalenko et al., in revision). Coastal wetlands are among the most vulnerable ecosystem types in the Great Lakes as a result of changing water level regimes, increased storm frequency and intensity, and increased surface water temperatures. Increased water levels and storm surges are detrimental to aquatic vegetation communities, and open shoreline wetlands are likely to be the most directly impacted. However, such storms are also associated with increased nutrient, sediment, and contaminant loading from tributaries and increased coastal erosion, which can directly impact habitat and biota in coastal areas. While phosphorus loading is anticipated to increase as a result of higher spring flow and increased storm events (LaBeau et al., 2015), phosphorus reduction targets for Lake Erie, in particular, are

expected to ameliorate this loading (Scavia et al., 2014), but current efforts may not be sufficient to prevent future cyanobacteria blooms and accompanying challenges to municipal water systems. Additional stressors impacting coastal areas include wetland drainage and diking, shoreline hardening, and human activities associated with shipping and recreation (Allan et al., 2013).

Warming water temperatures are expected to cause increases in primary production (Magnuson et al., 1997), but it is now clear that these changes are associated with changes in assemblage composition (Reavie et al., 2014). In shallow, coastal areas, increased primary production and warmer water temperatures will lead to more rapid decomposition, leading to the potential for summer hypoxia to develop (Nelson et al., 2009); increased hypoxia would exert a negative influence on the invertebrate community (Collingsworth et al., 2017).

Although water level fluctuation is a component of the natural hydrology of the Great Lakes, low water levels are a special concern in coastal systems especially when it leads to reduced hydraulic connectivity between tributaries and the lakes. This has multiple impacts on ecosystem structure and function affecting, for example, fish migration, flow of organic matter and other materials, and dispersal of invasive species (Januchowski-Hartley et al., 2013). Connectivity losses due to low water levels are exacerbated by physical structures in the watershed, such as dams and culverts, which impede movement between critical habitats during migration periods and when conditions are less than optimal, i.e., during periods with elevated water temperatures, and low dissolved oxygen (Nagrodski et al., 2012; Januchowski-Hartley et al., 2013).

Ice cover has declined across the Great Lakes region, with declines of 5 days per decade reported over the period 1974-2004 (Jensen et al., 2007). In coastal areas, ice cover serves to reduce wave action in shallow areas, thereby stabilizing the spawning habitat for fall and winter spawning species (e.g., lake whitefish). Lack of ice cover is also associated with further warming during summer months (Austin and Colman, 2007; Gronewold et al., 2015). Exposed shorelines and reduced ice protection increase the vulnerability of beaches, shorelines and bluffs to erosion (Mackey et al., 2012). Further, because human activity is so heavily concentrated along coastal regions, these areas are increasingly exposed to hazards that pose a threat to both infrastructure and human well-being.

5.7 Coastal processes

Hard rock shorelines in the Great Lakes such as those along the Canadian Shield on Lake Superior and eastern Georgian Bay, and the limestone and dolomites of the Niagara Escarpment in northern Lakes Huron and Michigan will for the most part not be significantly affected by climate change over the next 100 years. However, there is the potential for significant impacts on two types of shoreline that are especially important in southern Lake Huron, and much of Lakes Michigan, Erie and Ontario. These shoreline types are: 1) soft rock shorelines – bluff coasts developed in lacustrine silts and clay, glacial till, outwash sediments, and relatively weak shale bedrock; and 2) sandy beach and dune coasts, especially those formed on spits and baymouth barriers with their associated wetland systems. On both shoreline types, changes to wave characteristics over time (i.e., the wave climate) in each of the lakes is likely to have the greatest impact, and changes in mean lake level could be significant depending on the magnitude of the change.

The average annual wave climate at any point on the lake reflects primarily: 1) the shape of the lake and the fetch length for all onshore directions; 2) the average annual frequency and magnitude of winds by direction; and 3) the presence of ice during the winter which may act to reduce the open water fetch and/or to protect the beach

and parts of the nearshore from wave action (Barnes et al., 1994; Forbes and Taylor, 1994). The first factor is considered fixed and, because wave generation during large storm events is usually fetch-limited on all of the lakes, it acts to limit the potential impact of modest changes to the wind climate. As a result, the most important potential impact of climate change on the wave climate is the reduction in the duration and extent of winter ice cover due to global warming, and in particular warmer winter temperatures. This manifests itself as the increasing occurrence of open water conditions into January or February and the disappearance of ice cover in April and as early as March. There will also be more frequent years in which there is virtually no ice cover. This means that the coast will be exposed to a greater number of storm events each year and the effect is heightened by the fact that this additional open water occurs during a period of the year when storm intensity is generally greatest.

As discussed in Section 3.2, there was a significant reduction in the mean winter ice cover on Lakes Superior, Huron, and Michigan for the period 1973-2010 and similar trends have been noted for maximum ice coverage (Wang et al., 2012). In terms of the effectiveness of wave action on beaches and nearshore, a better measure is one that is linked to the ability of waves to reach the toe on cohesive bluff shorelines or the base of the stoss slope of sand dunes on sandy coasts. Here, 10% ice cover is used as a measure of the transition from unrestricted wave action to restricted wave action and 20% ice cover as the transition to complete protection of the shoreline and nearshore from wave action and severe restrictions on wave generation within the lake. The number of days with ice cover on Lake Erie greater than 10% and 20% for the winter-seasons 1973-74 to 2017-18 have decreased by 23 and 24 days, respectively over the 44 year time period (based on data from NOAA/GLERL, https://www.glerl.noaa.gov/data/). Winter ice cover >10% now averages about two months a year, and since 1997 there have been 6 years with fewer than 30 days with ice cover exceeding 20%.

An increase in the average number of storms in the winter months will have a direct impact on erosion of cohesive bluff shorelines and lead to an increase in the rates of bluff recession on all of the lakes. Because lake levels are generally low in the winter months, there may be limited increases in short-term bluff toe erosion, but erosion of the nearshore profile will be enhanced. In turn this will lead to an increase in the long term recession rate (e.g., Davidson-Arnott and Askin, 1980; Davidson-Arnott and Ollerhead, 1995; Trenhaile, 2009; Geomorphic Solutions, 2010a, b; Sunamura, 2015). It is likely that the increase in long-term recession rates will be on the order of 20-30% by the middle of the century. This is similar to the impact of reduced ice cover documented for areas such as the Gulf of St. Lawrence (Manson et al., 2016a) and the Arctic (Overeem et al., 2011; Irrgang et al., 2018). The increased rate of downcutting also puts additional stress on shore protection structures along these shores, leading to a reduction in lifetime expectancy (Keillor, 2003; Coldwater Consultants, 2010). Indirectly, warmer temperatures also lead to a decrease in the extent and duration of frost and snow cover on the bluff face and an increase in precipitation in the form of rain at a time when vegetation cover is at its lowest. This will enhance erosion of the sub-aerial bluff face due to overland flow and rill and gulley development and may also enhance the rate of shallow slumping (Mickleson et al., 2004).

Reduced ice cover in early and late winter may have an impact on sandy beach systems as a result of increased frequency of intense storm events generating large waves and extreme storm surge. There is therefore a greater probability of major dune erosion on mainland beaches, particularly during periods of high lake level. There is also increased potential for overwash and breaching of barriers, particularly at vulnerable locations such as the proximal end of spits, e.g., Presque Isle and Long Point on Lake Erie (Davidson-Arnott and Fisher, 1992; Matheus, 2016) and along baymouth barriers, e.g., those enclosing Sodus Bay and Hamilton Harbour on Lake Ontario.

The effects of an increase in the number of winter storms generating waves can also change the magnitude and direction of littoral drift within littoral drift cells along the lakes. Locally this may lead to a change from accretion to erosion and vice versa at some locations along the shoreline. However, because of the restrictions imposed by the size, shape and alignment of lakes, the potential impacts on the littoral sediment budget are generally relatively small. Pinpointing these locations will require generating an ice-free wind climate and using this to model the wave climate and in turn to use this as input to sediment transport models (e.g., Manson et al., 2015, 2016b).

There is now a good understanding of the effects of seasonal and long-term lake level fluctuations on the dynamics of cohesive bluff shorelines (e.g., Quigley et al., 1977; Geomorphic Solutions, 2010b) and of sandy beach shorelines (Olsen, 1956; van Dyck). Based on this, a decrease in mean lake level will result in reduced bluff recession rates for a period of several decades and dune progradation of sandy shores. Conversely, an increase in the mean lake level will result in an increase in the rate of bluff recession for several decades and landward migration of the shoreline and foredune on sandy beaches. In addition, we can use shoreline response in areas of ongoing isostatic uplift or drowning in parts of the Great Lakes basin as a proxy for shoreline response to an increase or decrease in the mean lake level resulting from climate change. The issue here is that it will likely take several decades to separate a change in mean level from the long-term fluctuations.

WATER SUPPLY DISRUPTIONS (LAKE ERIE/TOLEDO)

Lake Erie is the source of drinking water for many communities in northern Ohio, including Cleveland and Toledo. In 2014, the drinking water in Cleveland and 28 other water systems in Northeast Ohio were found to contain chromium, a cancer-causing toxin, in very small quantities that still met federal standards. In 2015, almost all of the water systems in Ohio produced tap water with detectable levels of the same seven or eight contaminants, sufficient to exceed health guidelines, but within federals standards.

A much bigger problem occurred in Toledo and parts of southeast Michigan in 2014 as a result of a harmful algae bloom in the water supply itself (Jane Herbert, https://www.canr.msu.edu/news/the_toledo_water_supply_shut_down._why_boil_water_advisories_were_not_enoug). Warming water temperatures and nutrient loading in Lake Erie were responsible. And boiling the water would have been insufficient – it would kill the organism but not eliminate the toxin. As a result, Toledo and other communities had to scramble to find alternative water sources.

Public and economic impacts of changes to the Great Lakes

The Great Lakes have an enormous number of impacts—seen and unseen—on the well-being of the more than 34 million people who live within the basin. We drink, play in, and rely on the Lakes for commerce and industry. Investments in ensuring long-term resilience to climate change are investments in the future stability and productivity of the region. While it is tempting to limit ourselves to studying more easily measurable strictly natural phenomena, there is ultimately no way to fully remove human social activities from our understanding of how climate change is affecting and will affect the Lake system. This section considers a selection of important public and economic activities influenced by the impacts described above.

6.1 Shipping

If lake level changes result from climate change, it can affect the ability of ships to safely navigate shallow portions of the Great Lakes' channels and harbors. The most important research in this area is primarily concerned with the "salties" that traverse the oceans in addition to the Great Lakes. Because of the distance these ships travel, the light loading needed to travel through shallow spots in the Great Lakes system during times of low water becomes particularly expensive in terms of tons of cargo hauled relative to time and fuel required.

Because the water level of Lake Michigan-Huron is especially sensitive to changes in the water budget, it largely determines the need for light loading. Millerd (2011) found that as much as a 1 meter decrease in the levels of Lake Michigan-Huron results in 3.6% to 12.2% increases in shipping costs (1.9% to 7.4% increase for a 0.7 m drop). The ranges result from differences in the types of goods shipped, as well as whether the cargo was inbound or outbound to the United States or Canada. Based on Lofgren and Rouhana (2016), the drops in lake levels used by Millerd (2011) should be regarded as very high-end estimates of water level drops within the 21st century. Shlozberg et al. (2014) found that any significant decrease in lake levels, like those found in the earlier studies, would have significant economic impacts, not only on shipping, but also through effects on hydroelectric generation, water use, and waterfront property values.

6.2 Water supply

Consumptive use is the amount of water withdrawn from groundwater or surface water that is not returned to the environment. Consumptive use data are more readily available for states than drainage basins such as the Great Lakes basin. The U.S. Geological Survey (USGS 2008) aggregated the withdrawal and consumptive use data for the eight Great Lakes states of Illinois, Indiana, Michigan, Minnesota, New York, Ohio, Pennsylvania, and Wisconsin by categories of use. The largest consumptive use is public supply — 1,200 million gallons per day (Mgal/day), or 4,540 million liters per day (Ml/d). This is out of a withdrawal of 10,200 Mgal/d (38,600 Ml/d), with the rest returned to the environment after treatment by a sewer system. This is the largest consumptive use category. It is followed by thermoelectric power at 1,100 Mgal/d (4,160 Ml/d), irrigation at 860 Mgal/d (3,260 Ml/d), industrial at 640 Mgal/d (2,420 Ml/d), livestock at 200 Mgal/d (757 Ml/d), self-supplied domestic at 130 Mgal/d (492 Ml/d), and mining at 94 Mgal/d (356 Ml/d). Compare this to a typical value of 16,000 Mgal/d (60,500 Ml/d) of outflow from Lake Ontario into the St. Lawrence River. The consumptive use seems to represent a highly significant fraction of the ultimate outflow from the Great Lakes.

Water consumption and climate change are related. The consumptive-use coefficient is the ratio of the amount of water consumed to the amount withdrawn, and its value by use category ranges from a median of 2% for thermoelectric use to a median of 90% for irrigation. The irrigation category is most likely to be strongly affected by climate change because of its high consumptive-use coefficient and increased evaporative demand in projected future climates. Fischer et al. (2007) examine evaporative demand from irrigated land on a global basis, and results differed considerably between the two global climate models that they used. In the UK Hadley center model, North America's irrigation needs were less than other parts of the world; while the Australia's CSIRO model show irrigation needs were comparable or larger. Fischer et al. (2007) also show that North America is generally more responsive to mitigation of human-generated greenhouse gas emissions and concentrations than most parts of the world. Globally, they estimate that US$10 billion in irrigation costs can be saved between 1990 and 2080 by shifting from a high emission scenario to a lower emission scenario.

The Great Lakes region and the eastern United States have particularly large percentage increases in irrigation water demand when comparing projections for the 2080s with a baseline in the 2000s (Wada et al., 2013). This is likely partially due to low irrigation water demand in the baseline period. With the amount depending on which scenario is followed, much of the Great lakes region has projected increases in irrigation –in the high scenario, nearly all of the eastern United States has increases greater than 25%.

Caution is warranted, however. Some of the offline hydrologic models used by Wada et al. formulate evapotranspiration very strongly based on temperature, rather than also including sunlight and other forms of radiation, and so overstate the influence of climate change on evapotranspiration (Milly and Dunne, 2016). In the Great Lakes Basin, these models overestimate the sensitivity of evapotranspiration to climate change at a much greater magnitude (Lofgren and Rouhana, 2016). Non-climatic drivers, such as development, changes in electrical power generation, and changes in agricultural and industrial practices, can also be expected to affect consumptive use in the future.

6.3 Infrastructure

Changing weather and climatic conditions in the Great Lakes put predictable stresses on existing physical infrastructure, such as roads and sewers. However, the fact that the condition and resilience of this infrastructure is heavily dependent on human investment and maintenance makes the long-term consequences of climate change on infrastructure less clear.

Climate change is very likely to have significant negative effects on source water quality that will put great stress on drinking water infrastructure. Nutrient runoff, primarily nitrogen and phosphorus washed off of farms and into surface waters, accumulates rapidly in a small number of intense rain events (Carpenter et al., 2018; Kleinman, 2006). These excess nutrients are directly hazardous for humans and feed massive algae blooms that dramatically raise the cost of water treatment (Michalak et al., 2013). The extra organic matter can react with water disinfectants, especially chlorine, to produce toxic disinfection byproducts (USEPA, 2015). Higher mean temperatures and more heavy precipitation events are favorable for this algal growth (Shigaki et al., 2007; Drake and Davenport, 2011).

Urban wastewater and stormwater systems also deliver significant nutrient loads to surface and groundwater (Preston, et al., 2011). Some of the largest cities in the Great Lakes region have combined sewer systems, which aggregate stormwater runoff and sewage. While this allows them to capture and treat this water collectively, it also creates a risk of combined sewer overflows (CSOs) when the sewer system is overwhelmed. This is most common during intense rain events in which large amounts of rain fall on areas with a high percentage of impervious surface. In these cases, the collected wastewater may be released untreated directly into surface water systems. The Great Lakes region has high numbers of federal action level exceedances for E. coli bacteria compared to other U.S. coastal regions (Hobbs and Mogerman, 2014; Patz, et al., 2008). This untreated effluent is a public health hazard and economically costly to mitigate.

Consider Chicago, the largest point source emitter of phosphorus in the Mississippi River Basin (Robertson et al., 2009). The city has made enormous investments in containment infrastructure designed to decouple intense rain events from CSOs (Hawthorne, 2018). However, the high percentage of impervious surface (59%) and increasing number of intense rain events associated with climate change make containing pollution difficult and expensive (Neuman et al., 2015). One can see that this is partially climate-driven by trends in river system "reversals" into

Lake Michigan (see Figure 10). The direction of the Chicago River was reversed in 1900 to shunt waste away from Lake Michigan. During periods of very heavy rain, water levels in the river system become high enough that they flow back into the lake. The volume of these reversals has continued over the last 25 years despite large gains in catchment capacity (USEPA, 2016; MWRD, 2017).

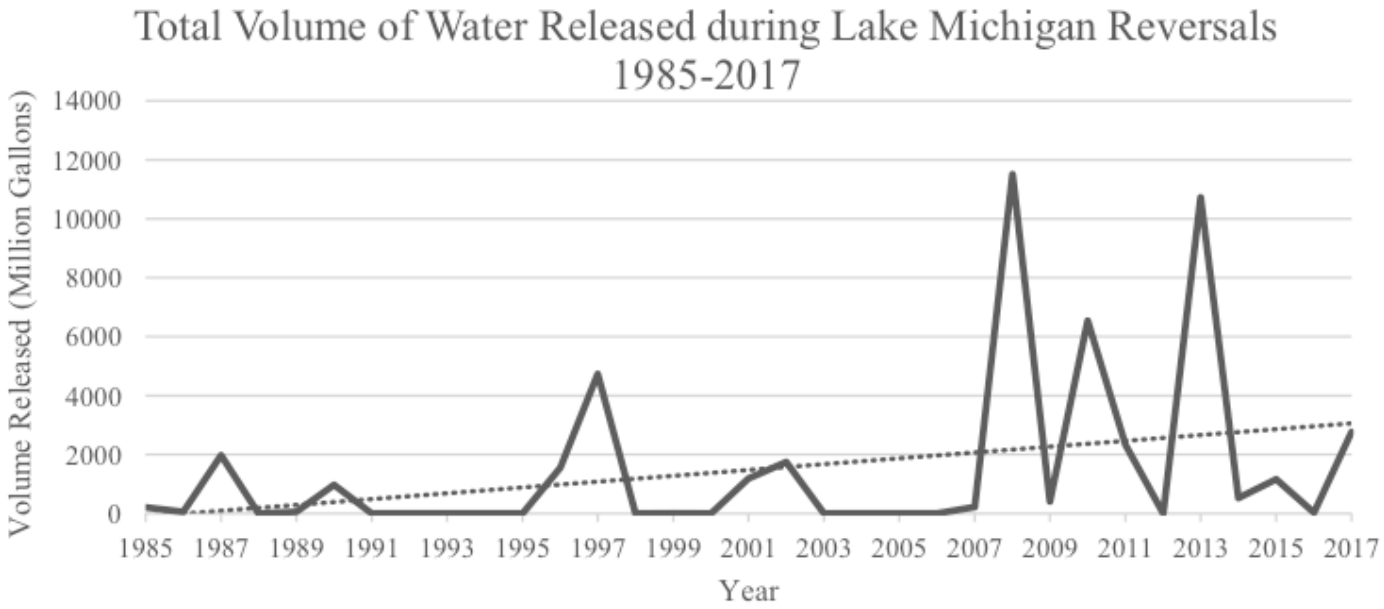


Figure 10. Combined volume of water released into Lake Michigan (Millions of Gallons) for the period 1985-2017 from O'Brien Lock, Chicago River Controlling Works (CRCW), and the Wilmette Gate. (Data source: Metropolitan Water Reclamation District)

Preparing water infrastructure for climate change in the Great Lakes region is expensive. Higher rates of HAB activity associated with climate change are likely to increase future treatment costs (Michalak et al., 2013). Investment for updating and maintaining water infrastructure has nevertheless decreased over the last few decades, at the same time as costs related to managing the effects of climate change are beginning to rise (Neumann, et al., 2015). Water treatment (both drinking water purification and waste treatment) accounts for 30%-40% of a municipality's energy costs (Copeland, 2014). Higher treatment demands resulting from climate-exacerbated runoff and sedimentation therefore translate rather directly into a higher carbon footprint (Cisneros, 2014). However, biological water treatment has been shown to be more efficient at higher water temperatures (Tchobanoglous, et al., 2003). Higher temperatures and longer dry periods also have the potential to reduce soil moisture to levels that can be harmful to buried pipe infrastructure through subsidence.

Other forms of infrastructure located on Great Lakes coastal areas are also affected by climate change. The Great Lakes coastlines include some of the densest road networks in the United States. Coastal roads are vulnerable to erosion from higher amounts of precipitation and wave heights, as well as damage from extreme heat (Swenson, et al., 2006). The high cost associated with updating these road systems for climate change result largely from the need to change the composition of asphalt binders in roads in order to handle higher temperatures and different freeze-thaw patterns (Chinowsky et al., 2013). Yet warmer winter temperatures and less ice on roadways

potentially have some positive effects including extending the life of road surfaces and reducing the need to use salt or ice-melting chemicals which wash into the water system.

Changes in precipitation and lake levels can have serious consequences for the health of fixed infrastructure. While projections of future lake levels are disputed, whether rise or fall, there are negative consequences for infrastructure (see Angel and Kunkel, 2010; cf. Lofgren and Rouhana, 2016). On a business-as-usual response to climate change and generally wetter future, 28.9% of road bridges within the U.S. Great Lakes Basin are vulnerable to damage from increased peak flows following rain events (Neumann et al., 2015). Not all of these bridges lie along coastal areas, but those face the additional threat of increased runoff and coastal erosion (Lofgren and Rouhana, 2016). Flood events make bridge scour—erosion around a bridge's supports caused by swiftly moving water—more likely. Scour is among the leading causes of bridge failure (Transportation Research Board, 2008).

Dropping lake levels and increasing temperatures pose a risk to electrical power production critical to the functioning of many other infrastructure systems, such as wastewater management. Most energy production in the Midwest U.S. is built along waterways, and the largest portion of water withdrawals from the Great Lakes (64.8%) is for once-through cooling for thermoelectric power plants (GLC, 2016). Lower lake levels and higher water temperatures both pose technical challenges for power generation. There is a concern about potential interruptions in thermoelectric power generation associated with decreased water levels, which may drop below water intake levels and increase energy required to pump water up to facilities. Increased temperatures reduce heat-transfer efficiency for cooling, which can limit power production to the level necessary to avoid overheating. Power plants along tributary waterways and the Great Lakes themselves are vulnerable to these effects. A critical issue is that energy infrastructure is built for long-term operation, and current energy infrastructure was built based on historical water levels and temperature regimes. Changes in climate that decrease water availability or effectiveness for cooling are therefore likely to decrease regional energy production.

6.4 Recreation

The outdoor recreational sector has grown to over 2% of value-added activity in the United States, and since 2014, growth in the outdoor recreational sector has outpaced growth in the economy as a whole (U.S. Bureau of Economic Analysis, 2018). The largest single activity is boating and fishing, accounting for around $38 billion in economic activity nationwide. Estimates have not been down-scaled to the Great Lakes, although some estimates of the economic contribution of various sectors have been made in the past. The Great Lakes Commission (2007) estimated that the economic contribution of boating in the Great Lakes was around $9 billion in 2003. A similar number of boats are registered in the region now, over 4 million according to the U.S. Coast Guard (2017), so the level of economic activity in boating is likely of similar scale (adjusted for inflation) at present. The effect of climate change on boating activities such as skiing or recreational boat driving will be driven by temperature changes, shifts in the length of seasons, and lake levels. The effects of these various changes could drive aggregate impacts upward or downward, however, no studies to our knowledge have attempted to assess the range of effects of climate change on recreational boating alone.

In contrast, there is significantly more information available on sports angling. The U.S. Fish and Wildlife Service (2017) estimates that 1.8 million anglers fish in the Great Lakes and its tributaries each year and they take 7.4 trips per year on average in the region for a total of 13 million trips. Nationally, anglers spend $10 per day on fishing related items, suggesting annual expenditures of about $133 million per year. The largest share of Great

Lake trips occurs in Lake Michigan, followed by Lake Erie. According to data collected by the U.S. Fish and Wildlife Service (2017), the number of anglers has increased over the last decade in the Great Lakes, but overall fishing days have declined. It is not clear what has caused these trends to emerge. Burkett and Winkler (2018) show a declining trend in license sales due to demographic shifts (e.g., aging cohort of male anglers). However, environmental factors cannot be ruled out as a causal factor related to declining participation. For instance, Wolf et al. (2017) have recently shown how HAB activity in Lake Erie reduces license sales.

While climate change could affect participation and expenditures in fishing, it may have more important effects on the value of ecosystem services related to recreational fishing in the Great Lakes. There is a large and robust literature valuing Great Lakes recreational activities, ranging from boating and fishing to beach recreation, as well as estimating how environmental changes affect recreational value (e.g., Provencher and Bishop, 1997; Murray et al., 2001; Provencher and Bishop, 2004; Yeh et al., 2006; Lupi et al., 2003; Melstrom and Lupi, 2013; Wolf et al., 2017; Zhang and Sohngen, 2017; Ready et al., 2018). Recent estimates of recreational fishing values in the Great Lakes region range from $20 per day to over $75 per day (Loomis and Richardson, 2008; Melstrom and Lupi, 2013; Ready et al., 2012). These estimates suggest that, at present, recreational fishing in the region provides ecosystem services values ranging from $0.3 to over $1.0 billion per year. These ecosystem service values exceed the effects of fishing on local economies, and imply that if climate change reduces the quality of ecosystem services, value could be lost even if the number of trips does not.

In preparing this review, no studies were found that directly addressed the role of climate change on fishing. Nonetheless, many of the stressors existing studies have addressed – invasive species, harmful algal blooms, e. coli contamination – are also likely strengthened by climate change. Ready et al. (2018), for instance, find that establishment of Asian carp in the Great Lakes could reduce anadromous fish populations in some of the most valuable parts of the fishery, namely Lake Michigan, reducing economic value by $139 million per year. The ranges of many fish species likely will change due to climate change (see section 5.4), shifting both trip intensity and economic value. For instance, coldwater fishing is more valuable than warmwater fishing, and anadromous fishing is the most valuable form of fishing the Great Lakes (Melstrom and Lupi, 2013; Ready et al., 2018). If climate change shifts the relative abundance of species composition towards warm-water types and away from cold-water types, then the overall value of fishing may decline over time. For instance, according to Melstrom and Lupi (2013), increasing the catch rate of coldwater species by 1 fish per trip enhances day trips by $40-$80 per trip, while increasing the catch rate of warm water species by one fish per trip enhances day trips by $1-$24 per trip.

Climate change could also have effects on recreation by altering aesthetic components unrelated to catch rates. Zhang and Sohngen (2017), for instance, show that fishing trip value in Lake Erie could be reduced by $40 per trip due to the presence of HABs. These reductions in value are driven by the lost amenity value associated with recreating in waters with diminished environmental quality rather than the effect of lost catch. Climate change is expected to exacerbate HAB activity in many parts of the Great Lakes (Section 5.3), potentially reducing the value of recreational activity.

Climate change could also influence beach recreation, either directly through temperature or indirectly through the effects on HABs and other pathogens that influence recreational activity. Murray et al. (2001) estimates that Lake Erie beach trips were worth $15-$25 per trip. Chen (2013) estimates that beach recreation in the lower peninsula of Michigan was worth $32-$39 per trip for day trips, and around $50 per day for multiple day trips,

for a total value of $400 million per year in recreational use value. It is not clear how climate change would affect beach recreation, given that warmer temperatures and longer seasons could spur increased visitation. However, if climate change reduces water quality and makes beach closures more likely, damages could grow. Murray et al. (2001) found that a single beach closure due to a pathogen like E. coli reduces recreational value by around $2 per trip, or around 10%. Palm-Forster et al. (2015) estimated the impact of HABs on beach recreation in Lake Erie, finding impacts of up to $2 million per year in lost recreational value if all beaches are affected.

Other recreational opportunities in the Great Lakes region, such as birding, are likely to be affected by climate change, although the effects are not known. What is known is that a large share of the population engages in bird and wildlife viewing, with 30-35% of the population engaged in this activity within a mile of their home in the Great Lakes States, and 8-12% engaged in this activity further than a mile from their home in the Great Lakes States (U.S. Fish and Wildlife Service, 2017). Loomis and Richardson (2008) suggest an average per day value of $25. Based on these two studies, there are around 139 million wildlife viewing trips away from home in the Great Lakes States each year, with an annual value of over $3 billion per year. The large majority of these trips involve birding, although it is difficult to know how many of these trips occur explicitly along the shores of the Great Lakes or within them. Climate change could affect the local habitat or the migratory patterns of many bird species frequenting the region, but integrated assessments need to be undertaken to determine how these would affect the avid population of people who engage in birding or other wildlife viewing activities.

Winter activities could experience the largest impacts of climate change. For instance decreases in the depth and duration of winter snow cover will result in fewer opportunities for winter recreation, including skiing, snowmobiling, and snowshoeing. Of the 122 resort-style businesses in the Great Lakes states currently identified as supporting winter recreation, only 80 are currently in areas that receive enough snow now to regularly support such activities (Chin et al., 2018). By the end of the century, under the highest emission scenario, all existing ski resorts in the region will become non-viable due to lack of snow and the conditions required to make snow. Duration and thickness of ice on small lakes is also decreasing (Mishra et al., 2011), potentially limiting the availability of sites suitable for ice fishing within the Great Lakes watershed.

6.5 Public health

As mentioned in section 4 and amplified upon in this section, the key vulnerabilities to public health as a result of climate change in the Great Lakes Region include those associated with rising temperatures and hydrologic extremes (Pryor et al., 2014; Patz et al., 2005). For those living across the Great Lakes Basin, heat waves and summertime air pollution events will increase the risk for heat-related illness and death, as well as respiratory diseases that often threaten the most vulnerable (elderly, those with existing conditions, children with asthma, etc.) (Luber and McGeehin, 2008; Kovats and Hajat, 2008; Bell et al., 2007; Mickley et al., 2004). Vector-borne disease is also expected to increase as conditions become more favorable for insects that carry disease (i.e., shifts in the range of mosquitos, ticks, etc.) (Gubler et al., 2001). Increasing variability in rain events will lead to seasonal flooding and drought events, creating issues with the availability of high quality water for drinking and other human uses (see Section 6.3 and 6.6). Issues with flooding and standing water can also increase the incidence of water-borne disease (Patz et al., 2008; Curriero and Patz, et al., 2001). Finally, the indirect effect of climate change on the Great Lakes region may be through the psychological or mental health impacts of social, demographic and economic disruption (Clayton et al., 2017; McMichael et al. 2006).

Of particular concern within the Great Lakes themselves are the microcystin, pathogens, and bacteria that increase in downstream water bodies during intense rain events. Extensive harmful algal blooms are expected to increase in frequency and severity under climate change, and they present multiple threats to public health. Cyanobacteria-dominated HABs can produce several toxins, such as anatoxins, saxitoxins, cylindrospermopsin, nodularins, and microcystins (Cheung et al., 2015). Exposure to cyanotoxins can occur through ingestion, inhalation, and dermal contact pathways. Ingestion during recreation and consumption of contaminated drinking water are the most common exposure cases (USEPA, 2017). However, increased concern has been raised over the ingestion of contaminated seafood and vegetables, which can accumulate cyanotoxins (Lee et al., 2017; Wituszynski et al., 2017). Furthermore, interaction with soils irrigated with HAB contaminated waters, can lead to dermal exposure and possibly irritation and rash development. Finally, cyanotoxins can accumulate in fish tissue, therefore consumption of fish from frequently blooming waters may lead to additional cyanotoxin exposures (Wituszynski et al., 2017). Inhalation is another route of exposure to cyanotoxins. It happens by breathing in bioaerosol and mist from a HAB-affected water body. Those who regularly work on or near water get exposed via inhalation (boaters, anglers and lifeguards, for example). Further research is recommended to better understand the chronic effect of toxin inhalation (Backer et al., 2010).

6.6 Impacts on Indigenous people in the Great Lakes Basin

There are many communities of Indigenous people and tribes within the Great Lakes region, especially within the Great Lakes Basin. Though they may also be affected by climate change in ways that are similar to others in the United States, Indigenous peoples can also be affected uniquely and disproportionately (USGCRP, 2018). Climate impacts to lands, waters, foods, and other plant and animal species threaten cultural heritage sites and practices that sustain intra- and intergenerational relationships built on sharing traditional knowledges, food, and ceremonial or cultural objects. The 4th National Climate Assessment (USGCRP 2018, and references therein) found that "Climate change threatens Indigenous peoples' livelihoods and economies, including agriculture, hunting and gathering, fishing, forestry, energy, recreation, and tourism enterprises. Indigenous peoples' economies rely on, but face institutional barriers to, their self-determined management of water, land, other natural resources, and infrastructure that will be impacted increasingly by changes in climate." They also found that Indigenous health is based on interconnected social and ecological systems that are being disrupted by a changing climate.

6.7 Industrial needs for water

The freshwater resources of the Great Lakes underwrite a significant portion of the region's economic productivity (Campbell et al., 2015). Considering both the United States and Canada, consumptive industrial uses represent 4,465 million gallons per day (mgd) or 10.8% of total withdrawals for consumptive use, outpaced only slightly by public drinking water consumption at 5,537 mgd or 13.1% (GLC, 2016). The amount of water consumed by industry over the last thirty years, however, has remained relatively stable (see Figure 11). Given that water resources have become progressively more regulated and competitive over time, there is little indication that water will, in general, become cheaper for industry. Some have speculated that businesses currently located in less water-secure places will begin to migrate toward the region (e.g., Austin and Steinman, 2015). But because the price of water is heavily mediated by policy and regional economics, local scarcity or abundance does not tell us much about the attractiveness of water development all by themselves (Shaw, 2007). Midwestern Great Lakes states, because of their historical contributions to transportation equipment, heavy manufacturing, energy production, and agriculture produce more than a quarter of national greenhouse gas emissions (Livingston et al., 2009).

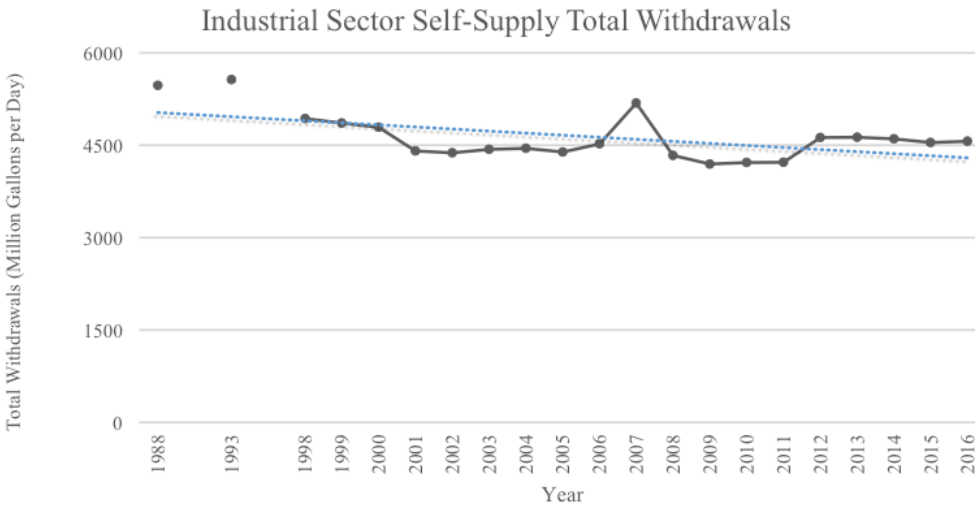


Figure 11. Total volume of water withdrawn from the Great Lakes for the period of 1988-2016 by the industrial sector. Data source: Great Lakes Regional Water Use Database

There has long been speculation that the water itself would become a major commodity—bottled and shipped as bulk water or pumped out of the region via inter-basin transfers. This is unlikely as large interbasin transfer schemes to move water long distances from the lakes are economically impractical (Annin, 2018). Bottled water has not represented a significant stress compared to other regional consumptive uses, especially given the amount of water diverted into the lake system (IJC and CMI, 2000). A large portion of bottled water is packaged tap water, however, and is thus folded into public drinking water consumption (Hu et al., 2011).

Existing industrial demands in a variety of sectors are very sensitive to changes in water availability and quality related to climate change. Agriculture, refineries, and commercial fishing offer examples of impact. Agricultural consumption generally increases with higher temperatures and longer dry periods (Schoengold and Zilberman, 2007). If regulatory action is taken to control nutrient pollution flows from farm and livestock operations created by more intense rainfall, it will increase the cost of farm operations (Rathinasamy et al., 2015). Fuel refineries along Great Lakes coastlines continue to represent a large portion of industrial withdrawals (USGS, 2008; Wu et al., 2009). While the number of refineries operating in the region has declined over the last 30 years, as these refineries increase in size, water consumption will increase in proportion to their overall crude processing capacity (US EIA, 2018; Wu, et al., 2009). The commercial fishing industry is directly impacted by climate related changes in water quality in particular. Invasive species and oxygen level changes have produced an average of 3.5% decline in yield per year across all the Great Lakes (Brenden et al., 2012; see 6.4 above).

It is unclear whether regional diversion regulations will constrain future industrial uses. The 2008 Great Lakes—St. Lawrence River Basin Water Resources Compact ("Great Lakes Compact"), severely restricts the amount of water that can be diverted out of the Great Lakes Basin and puts environmental review conditions on large new consumptive uses within the basin. However, it was designed mainly to control the expansion of municipal uses beyond the basin line by regulating new consumption by utilities, rather than new large industrial uses.

The most recent high-profile test of this by water intensive industry relocating to the Great Lakes Basin is the planned development of a Foxconn liquid crystal display factory in the Village of Mount Pleasant, Wisconsin. The Wisconsin Department of Natural Resources has granted the southwest portion of the City of Racine a diversion allowance of up to 7 mgd, much of which is expected to go to the Foxconn plant (Thomas, 2018). The State of

Wisconsin, in order to encourage the construction of the plant, waived or weakened diversion restrictions, air pollution control permits, stormwater permits, and pretreatment requirements (MEA, 2018). Foxconn ultimately pulled out of the deal. So far, this is an isolated case, but if it were to become a general trend in the region, it would create intense new demands on water resources given that individual factories can consume about the same amount of water every day as a small city.

BEACH CLOSURES AND RISKS OF GETTING SICK DURING RECREATION.

Fifteen Michigan beaches were either closed or are under advisories because of bacterial contamination during the 2018 Labor Day weekend. In June 2018, 24 Michigan beaches were closed because of elevated bacteria levels, just when a heat wave made it especially desirable for people to head to the beach. This is not an uncommon occurrence, especially during the summer months, on the coastlines of the Great Lakes.

Summer is also the time of algal blooms and E.coli alerts -- and that can put a damper on plans to cool off. While various studies (e.g., Never et al., 2018) have shown that fecal matter from gulls and pets are a major contributor, climate change is also a factor. The increase in the frequency and intensity of extreme precipitation events are likely to exacerbate the issues associated with runoff and the associated effects on bacterial counts.

Conclusions

Allowing the vast, natural resource of the Great Lakes to be taken for granted and degraded through human activities, including the effects of climate change, is not an option. For economic, aesthetic, and ecological reasons, we need the Great Lakes to remain healthy, unpolluted, and productive. Climate change is already having an impact on the region, and there is evidence that such impacts may increase under expected future climate change. Responding to these stressors requires both adaptations to the impacts that cannot be avoided (e.g., improving agricultural land management to decrease nutrient loading), as well as mitigation to reduce the possibility of experiencing the most extreme impacts (e.g., decreasing carbon emissions from the household to the industrial sector). Public support for protecting the Great Lakes is strong across the region, and despite differing concern about climate change as a threat, overall public support for action to address climate change is high. It is critical that we recognize the importance of this freshwater resource and ensure its protection for generations to come.

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Supplementary Material
An Assessment of the Impacts of Climate Change on the Great Lakes

Development of the Graphics

While some of the graphics in the Assessment are based on existing peer-reviewed publications or on websites associated with observational datasets, some of the graphics is produced for this assessment based on other datasets. The analyses of the past and projected climate changes are derived based on the analyses of observational datasets for past changes and from modeling and downscaled datasets for projections produced for NCA4 (USGCRP, 2017, 2018). The reference periods used in these analyses are the same as those used in NCA4. Projections use a weighting system for global climate models, that are then statistically downscaled for temperature and precipitation at about 6 km resolution across the continental United States based on the LOcalized Constructed Analogs approach (LOCA; Pierce et al. 2014) that spatially matches model-simulated days, past and future, to analogs from observations.

Until NCA4, assessments used a simple averaging of the multimodel ensemble. NCA4 uses model weighting to refine future climate change projections. In NCA4, model independence and selected global and North American model quality metrics are considered in order to determine the weighting parameters (Sanderson et al., 2017, building upon the earlier study by Knutti et al., 2017). The weighting approach takes into account the interdependence of individual climate models as well as their relative abilities in simulating North American climate. Understanding of the calculated time history, together with the fingerprints of particular model biases, has been used to identify model pairs that are not independent. Thus, this approach considers the skill in the climatological performance of the models for the area over North America as well as the inter-dependency of models.

Projections are based on global models and downscaled products from CMIP5 (Coupled Model Intercomparison Project Phase 5) using a suite of Representative Concentration Pathways (RCPs). Figure 1 shows the projected changes in globally averaged temperature for a range of future pathways that vary from assuming strong continued dependence on fossil fuels in energy and transportation systems over the 21st century (the high scenario is Representative Concentration Pathway 8.5, or RCP8.5) to assuming major emissions-reduction actions (the very low scenario, RCP2.6).

Most of the graphics in this report will use either the high RCP8.5 scenario or the low RCP4.5 scenario. At the higher end of the range, the RCP8.5 scenario corresponds to a future where carbon and methane emissions continue to rise as a result of fossil fuel use, albeit with significant declines in emission growth rates over the second half of the century, significant reduction in aerosols, and modest improvements in energy intensity and technology (Riahi et al., 2011, USGCRP, 2017). RCP8.5 reflects the upper range of the open literature on emissions, but is not intended to serve as an upper limit on possible emissions. RCP4.5 assumes a rapid movement away from the fossil fuels over the coming decades. Under the RCP8.5 scenario, CO¬2 concentrations are projected to reach 936 ppm by 2100. Under the lower RCP4.5 and RCP2.6 scenarios (van Vuuren et al., 2011; Thomson et al., 2011), atmospheric CO2 levels remain below 550 and 450 ppm by 2100, respectively.

For future projections, 30-year periods are used. Projections are centered around 2030, 2050, and 2085 with an interval of plus and minus 15 years (for example, results for 2030 cover the period 2015–2045). The reference period for these projections is the recent past, from 1976–2005. The choice of a 30-year period is chosen to account for natural variations and to have a reasonable sampling in order to estimate likelihoods of trends in extremes; this period is consistent with the World Meteorological Organi¬zation's recommendation for climate statistics.

Additional figures on Climate Changes in the Great Lakes region

Figure A1 shows observed percentage changes in precipitation for the U.S. states bordering the Great Lakes for present day (1986-2016) relative to 1901-1960. All of these states show an increasing trend except for a few isolated locations in Michigan (especially the Upper Peninsula), Ohio, and Pennsylvania that show a minor decrease in precipitation. However, future precipitation for 2085 period (2070-2099) relative to 1976-2005 for both RCP 8.5 and 4.5 show increases in precipitation all across the Great Lakes states (Figure A2). With the high emission scenario (RCP8.5), the precipitation is projected to generally increase 8-10% evenly across all of the Great Lakes states, but with a strong seasonal dependence (especially more in winter and spring, less in summer). The RCP4.5 scenario projects an overall increase of 6-10% for the Great Lakes basin and the eastern Great Lakes states by the end of the century. The rest of the region shows a more moderate 2-4% increase in annual precipitation.

For extreme events related to temperature, the projections show high variability across the Great Lakes states. For example, an increasing trend for future extreme warm days with temperature greater than 90°F is projected for both RCP 8.5 and RCP4.5 (Figure A3). However, due to the presence of the Great Lakes, the basin region shows relatively less number of extreme warm days in comparison to the rest of the region. In general, it is projected that the southern Great Lakes region will have more than 100 days with a temperature greater than 90°F for RCP8.5. For the lesser emissions of the RCP4.5 scenario, parts of southern Illinois and Indiana project 60-70 extreme warm days and the rest of region projects a smaller increase in extreme warm days. In general as rule of

thumb, the upper limit in the uncertainty range for RCP4.5 wprojects to be about the same as the lower limit for the higher emissions RCP8.5 scenario for future extreme warm days in the Great Lakes states.

Likewise, future climate warming will reduce the extreme cold days with temperature less than 32°F (Figure A4). The decrease in extreme cold days is projected to be much larger for RCP8.5 in comparison to RCP4.5 – the Great Lakes basin is greatly affected for both future scenarios. Similarly, the future extreme events with a 5-year return period show an increase (Figure A5). This increase is as high as 25% in many parts of the Great Lakes region for RCP8.5. For the lower RCP4.5 scenario, most of region projects about a 10% increase by the end of the century, with about a 15% increase in eastern Pennsylvania and New York.

For snow analysis, snowfall was determined using a criterion of daily mean temperature below −0.5°C for any precipitation days for both the observed and the statistically-downscaled climate model-based data (Byun and Hamlet, 2018). A decrease in annual snowfall in the Great Lakes states for the period from 1984 to 2013 has been observed (Figure A6). Future snow projections are calculated based on the ensemble mean of statistically-downscaled analyses of ten global climate models for the RCP8.5 and for RCP4.5 scenarios. With a significant warming in future during the winter months, both the RCP 8.5 and 4.5 scenarios project a substantial decrease in snowfall over the ground by the end of the century (Figure A7). Minnesota is likely to get less reduction in snow in comparison to all other Great Lakes states.

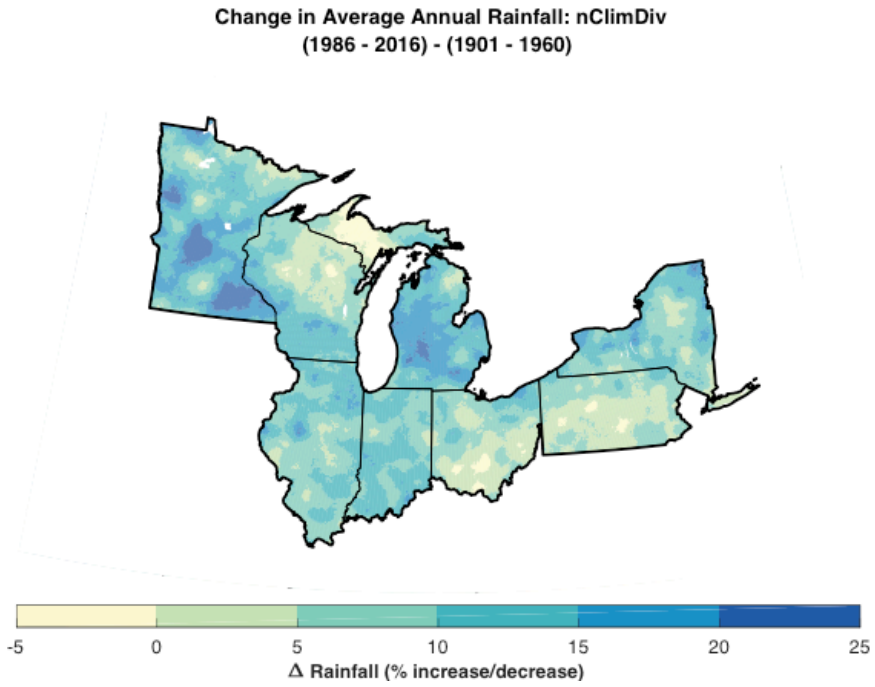

Figure A1. Observed changes in annual precipitation (as equivalent rainfall) (%) for the U.S. states bordering the Great Lakes for present-day (1986–2016) relative to 1901–1960. Derived from the NOAA nClimDiv dataset (Vose et al., 2014). (Figure source: NOAA/NCEI)

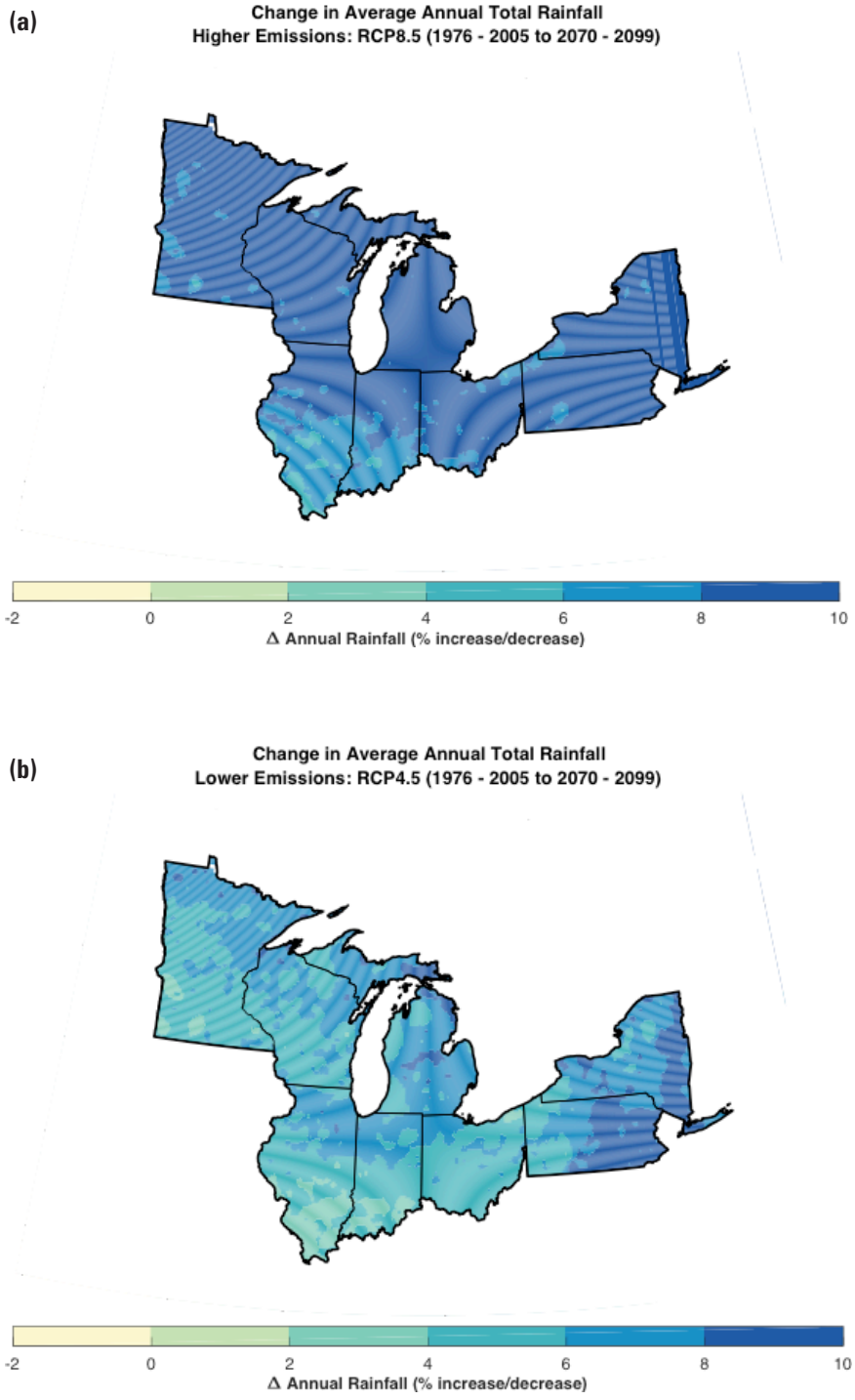

Figure A2. Change in annual precipitation (as equivalent rainfall) (%) for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. (Figure source: NOAA/NCEI)

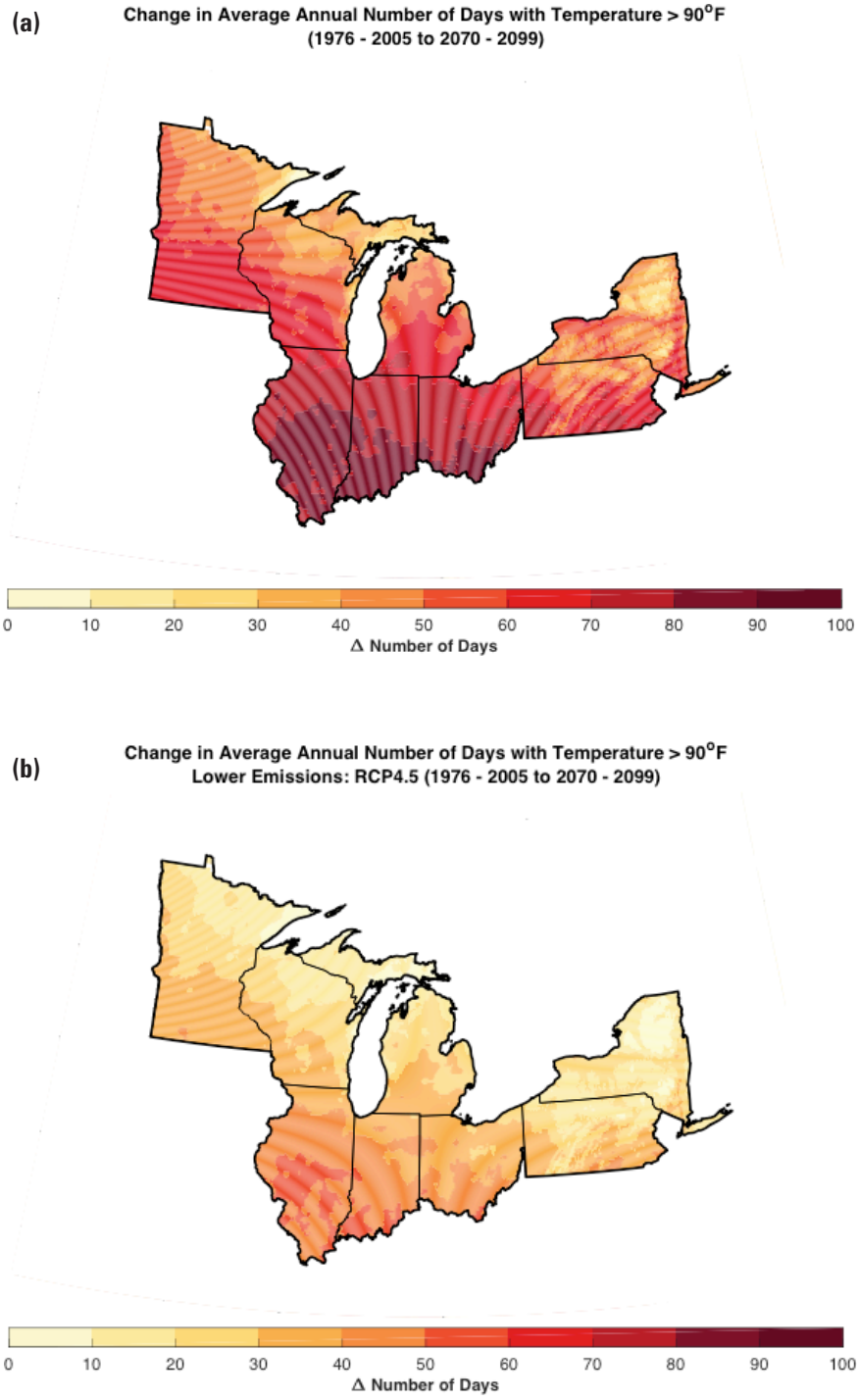

Figure A3. Change in the number of days with temperature greater than 90°F for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. (Figure source: NOAA/NCEI)

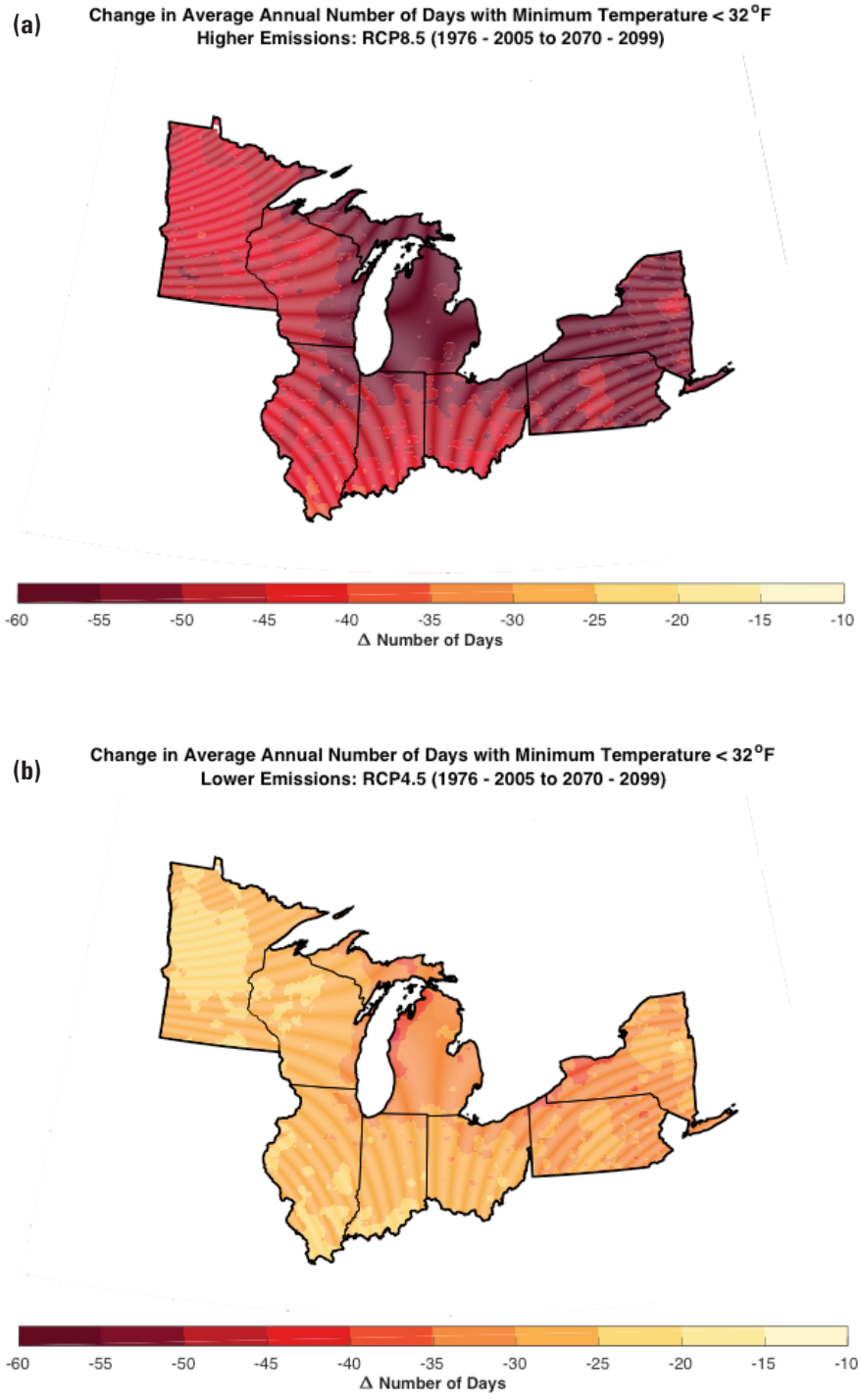

Figure A4. Change in the number of days with temperature less than 32°F for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. (Figure source: NOAA/NCEI)

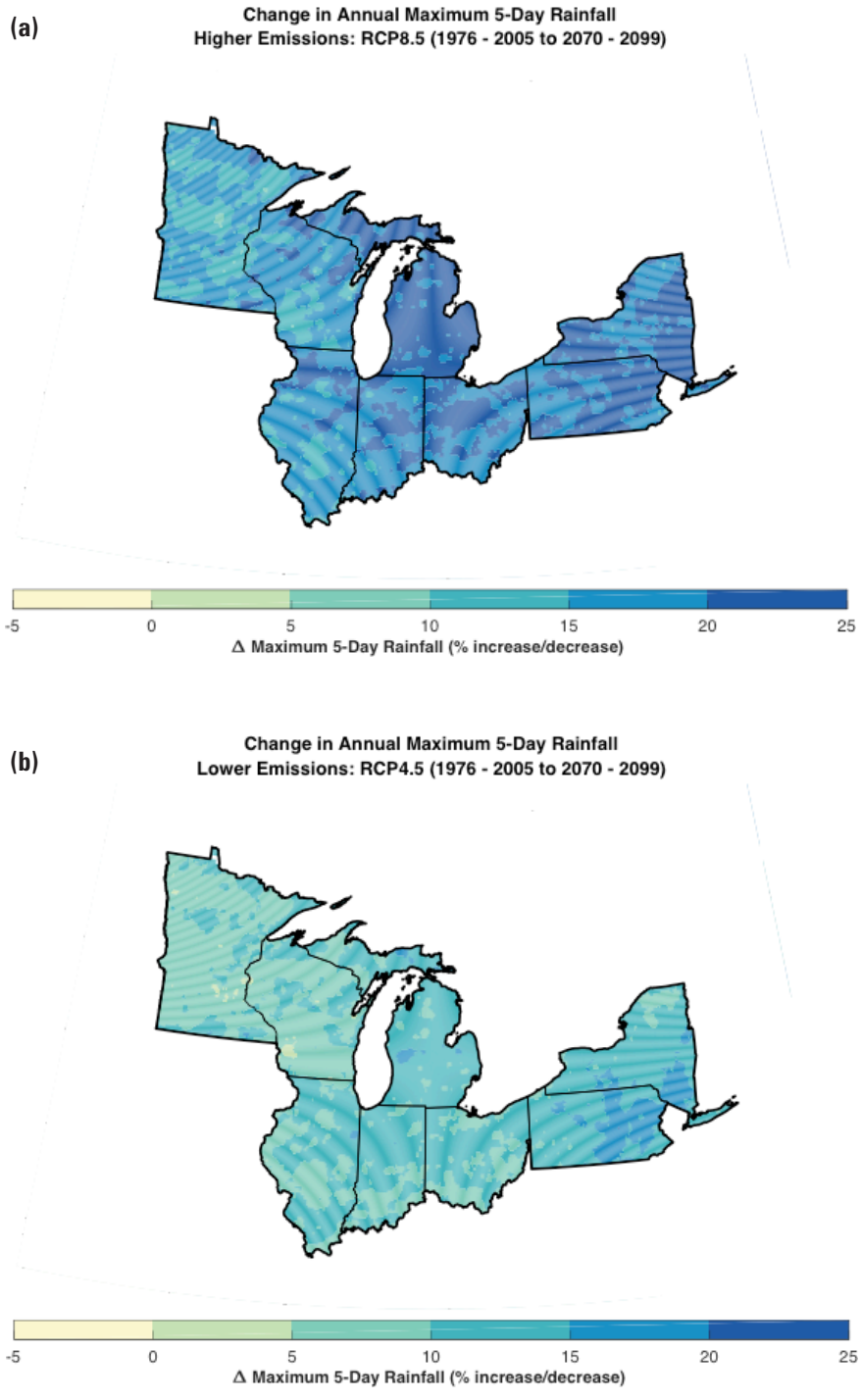

Figure A5. Percentage change in annual maximum five-day rainfall amounts for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. (Figure source: NOAA/NCEI)

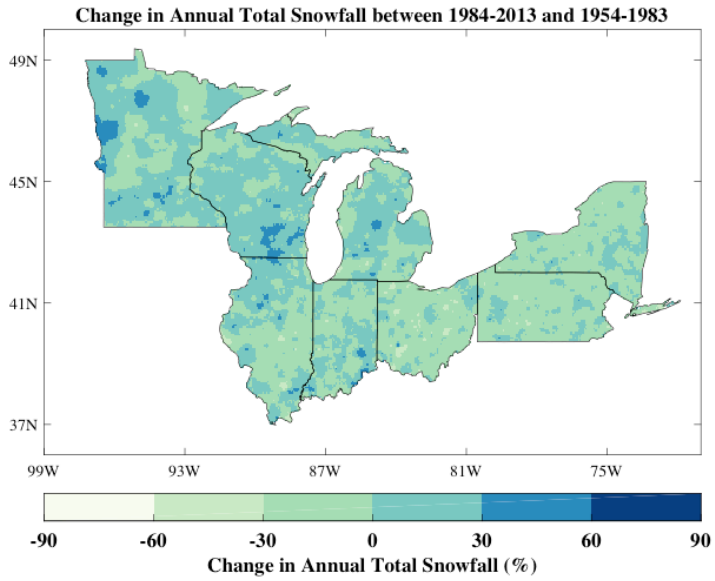

Figure A6. Observed changes in annual snowfall (%) for the U.S. states bordering the Great Lakes for present-day (1984-2013) relative to 1954-1983. Derived from bias corrected and gridded observational station dataset (Byun and Hamlet, 2018).

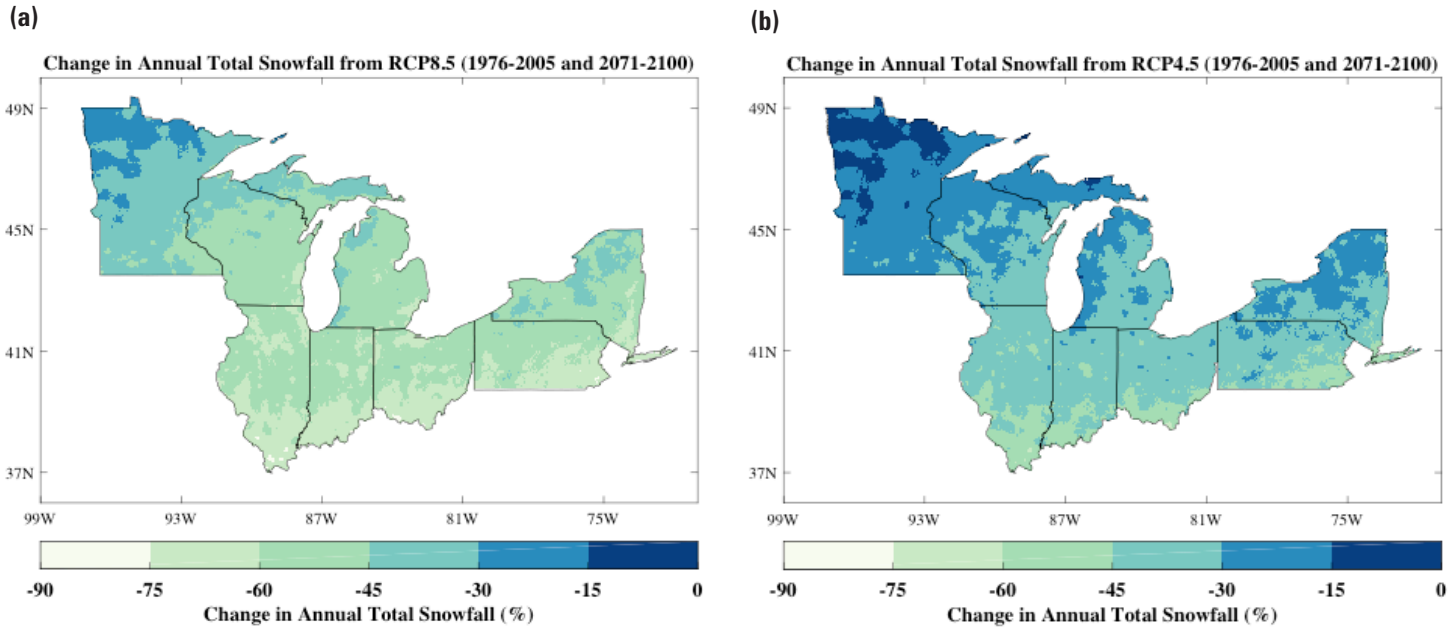

Figure A7. Change in annual snowfall (%) for U.S. states bordering the Great Lakes from the (a) higher (RCP8.5) and (b) lower (RCP4.5) scenarios for the 2085 (2070-2099) time period relative to 1976-2005. Derived from the ensemble mean of 10 statistically-downcaled CMIP5 GCMs by Hybrid Delta method (Byun and Hamlet, 2018).

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LAKE ONTARIO WATER TEMPERATURE IN A CHANGING CLIMATE

Final Report

May 2017

OURANOS

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The CRCM5 was developed at the ESCER Centre at UQAM (Université du Québec à Montréal), with the collaboration of Environment and Climate Change Canada. CRCM5 computations were made on the supercomputer guillimin from McGill University, managed by Calcul Québec and Compute Canada. The operation of this supercomputer is funded by the Canada Foundation for Innovation (CFI), the ministère de l'Économie, de la science et de l'innovation du Québec (MESI) and the Fonds de recherche du Québec – Nature technologies (FRQ-NT). We also thank NSERC and CFCAS for the funding of the development of the CRCM5.

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EXECUTIVE SUMMARY

Since the temperature of cooling water directly impacts the efficiency of nuclear power plants, we are interested in understanding how the temperature of Lake Ontario will be affected by climate change. This report presents an overview of mid-term (2041-2070) changes in the temperature of Lake Ontario at the annual and seasonal scales.

Two ways to evaluate water temperature using only air temperature are explored: the first one consists of a simple linear regression between observed water temperature and observed air temperature; the second one consists of using the *air2water* model, a semi-empirical model based on the energy budget of a lake. Observation datasets include water temperature from Darlington Nuclear Power Station intake, air temperature from nearby Environment and Climate Change Canada (ECCC) weather stations and from the Natural Resources Canada (NRCan) gridded dataset. The empirical and *air2water* models are used to evaluate future water temperature from projections of air temperature. Projected air temperatures are determined from a 12-member ensemble of Regional Climate Model (RCM) simulations, using the RCP4.5 and RCP8.5 emission scenarios.

Our analysis shows that water temperatures in cooler years may depart significantly from water temperatures derived using the simple linear statistical model. Better performance is obtained with the *air2water* model. Although the *air2water* model is formulated to evaluate lake mixed layer temperature rather than water temperature deeper into the lake, it was still able to fairly simulate intake temperature over the validation period.

Even if values of projected air temperature vary among climate models, all RCMs project an increase in air temperature at annual and seasonal scales. The expected warming of Lake Ontario water temperature is smaller than that of air temperature, which is consistent with historical observations of air and water temperature. At the annual scale, ensemble-mean water temperature increases by 1.2°C and associated uncertainties are evaluated at [0.8-1.5]°C with the first method, and 0.8 [0.5-1.0]°C with the second method. In summer, ensemble-mean water temperature increases by 1.9°C and associated uncertainties are evaluated at [1.2-2.6] °C with the first method and 0.9 [0.5-1.2]°C with the second method. The first method yields larger increases of water temperature than the second, probably due to its inability to consider the redistribution of energy in the active volume of the lake. Also, since the seasonal variability of air temperature deltas is small, annual and seasonal water temperature changes from the second method are similar.

TABLE OF CONTENTS

1 Introduction 1
2 Literature review 2
2.1 Lake energy budget and stratification 2
2.2 Evaluating lake surface temperature (LST) 4
2.3 Climate change and LST 6
3 Data and Methodology 11
3.1 Datasets 11
3.1.1 Observations 11
3.1.2 Climate change assessment data 13
3.2 Two methods to project future water temperature 16
3.2.1 First method – linear regression 16
3.2.2 Second method – *air2water* modeling 17
4 Results and discussion 19
4.1 Observations 19
4.1.1 Annual 19
4.1.2 Summer 20
4.2 Differences between simulations 21
4.3 Air temperature projections 22
4.3.1 Annual 22
4.3.2 Summer 23
4.4 First method – linear regression 24
4.4.1 Annual 24
4.4.2 Summer 25
4.5 Second method – air2water modeling 26
4.5.1 Annual 27
4.5.2 Summer 27
5 Conclusions 29

Annex A. Supplementary material 30
A.1. Regional Climate Models used in this study 30
A.2. Water temperature projections.....31

LIST OF FIGURES

Figure 1. Components of a lake energy budget, adapted from Bailey et al. (1997). All terms are expressed in W m-2..... 2
Figure 2. Typical mixing and stratification in dimictic lakes, adapted from Shaw et al. (2004). 3
Figure 3. Relation between monthly air temperature and water temperature at Lake Mendota, taken from McCombie (1959)..... 4
Figure 4. Observed air temperature (light blue dots), observed lake surface temperature (dark blue dots) and simulated LST using the air2water model with 6 and 4 parameters, taken from Piccolroaz (2016)..... 5
Figure 5. Mean annual ice cover averaged over all Great Lakes, adapted from Wang et al. (2012). 6
Figure 6. Great Lakes water level observations (NOAA, 2016). 7
Figure 7. Lake Ontario open water temperature cycle for the period 1971-2000 (black) and the period 2071-2100 (grey) under scenario A2, adapted from Trumpickas et al. (2009)..... 9
Figure 8. Location of Darlington (red dot) and Pickering (grey dot) nuclear power plants as well as Environment and Climate Change Canada weather stations (green triangles). 11
Figure 9. Interannual cycle of 2-m air temperature from multiple datasets. 13
Figure 10. Changes in radiative forcing, adapted from van Vuuren et al. (2011).....14
Figure 11. Annual series of observed air (black) and water (green) temperatures for the Darlington site. Since over 40% of the water temperature data in 1999 was missing, that year was removed from the annual analysis. 19
Figure 12. Annual series of summer a) mean air (black), intake (red) and lake surface (blue) temperature and b) anomalies in air (black), intake (red) and lake surface (blue) temperatures, with regard to the available data of each time series. 20
Figure 13. Projected change in annual precipitation versus change in annual air temperature for each simulation of the ensemble. Deltas were calculated by subtracting long-term averages of reference values (1986-2015) from future values (2041-2070). Each simulation is identified as: RCM (driving GCM) and future emission scenario. 21

Figure 14. Anomalies in annual air temperature versus anomalies in annual water temperature, with regard to the 1991-2015 period, for the Darlington site. Symbols r and R^2 represent correlation and the coefficient of determination, respectively. 24
Figure 15. Anomalies in summer air temperature versus anomalies in summer water temperature, from a) the Global Lake database (GLD) with regard to the 1991-2009 period, and from b) Darlington intake with regard to the 1991-2015 period. 25
Figure 16. Daily observed air temperature (in grey), daily observed water temperature (in blue) and daily water temperature simulated by the air2water model (in yellow) for the period 2006-2015, at the Darlington site. 26

Figure A. Ensemble mean (black circles), 25th percentile (blue dots) and 75th percentile (orange dots) of changes in intake temperatures at Darlington for annual (left side) and summer (right side) time scales, obtained from the two methods used in this study. Projected changes in temperature are evaluated by subtracting long-term averages of reference values (1986-2015) from future values (2041-2070).....31

LIST OF TABLES

Table 1. Historical and projected changes in water temperature in the Great Lakes and Minnesota Lakes. 8
Table 2. Projected Tmax, J10spring and J10fall under A2 and B2 scenarios for Lake Ontario, adapted from Trumpickas et al. (2009). 10
Table 3. Characteristics of provided water temperature datasets. 12
Table 4. Description of weather stations from ECCC network. 12
Table 5. Representative Concentration Pathways, adapted from Moss et al. (2010). The radiative forcing column indicates the approximate surplus energy flux that accumulates in 2100 due to GHGs; the CO2 equivalent indicates the concentration of GHGs in the atmosphere, and the pathway describes the emission trajectory. 14
Table 6. Equation and time window of components used in climate change assessment studies. Data taken from climate models is indicated in bold. 17
Table 7. Statistics of annual observed air and water temperature over 1991-2015. 19
Table 8. Statistics of summer observed air as well as Darlington intake and surface water temperature. 21
Table 9. Description of Regional Climate Simulations used in this study with their corresponding emission scenario (RCP), annual air temperature in the reference (1986-2015) and future period (2041-2070), deltas (2041-2070 minus 1986-2015) as well as percentile of each delta. RCMs are listed in ascending order of their deltas for the Darlington site. 22
Table 10. Description of Regional Climate Simulations used in this study with their corresponding emission scenario (RCP), summer air temperature in the reference (1986-2015) and future period (2041-2070), deltas (2041-2070 minus 1986-2015) as well as percentile of each delta. RCMs are listed in ascending order of their deltas for the Darlington site. 23
Table 11. Observed, deltas and perturbed annual air temperature (Ta) and intake temperature (Tw) from the first method for the Darlington site. 25

Table 12. Observed, deltas and perturbed summer air temperature (Ta) and intake temperature (Tw) from the first method for the Darlington site. 26
Table 13. Parameters obtained by calibration of the air2water model over the 1991-2005 period for the Darlington site. 26
Table 14. Observed, deltas and perturbed annual intake temperature (Tw) from the second method for the Darlington site. 27
Table 15. Observed, deltas and perturbed summer intake temperature (Tw) from the second method for the Darlington site. 27

Table A. RCMs considered in this study....30

GLOSSARY

CC: Climate Change

CORDEX: Coordinated Regional Climate Downscaling Experiment

DOY: Day of the year

DNPS: Darlington Nuclear Power Station

ECCC: Environment and Climate Change Canada

GCM: Global Climate Model

GHG: Greenhouse gas

GLD: Global Lake Database

IPCC: Intergovernmental Panel on Climate Change

JAS: July-August-September

LST: Lake surface temperature

NRCan: Natural Resources Canada

OPG: Ontario Power Generation

RCM: Regional Climate model

1 INTRODUCTION

A nuclear reactor, as any other heat engine, requires coolant to condense the steam driving the turbines. Because the efficiency of a heat engine depends on the temperature differential, the colder the intake water temperature, the more efficient energy generation is. This cooling water is then returned to the environment at a higher temperature, subject to regulations to limit detrimental environmental impacts. The nuclear stations operated by Ontario Power Generation (OPG) at Pickering and Darlington use Lake Ontario water as the coolant. OPG has thus an interest in better understanding how Lake Ontario water temperature could be affected by climate change (CC).

The main objective of this report is to provide an overview of how climate change could impact Lake Ontario water temperature. The second chapter presents a literature review. Then, the data as well as the general methodology are described. In the results chapter, preliminary projections of water temperature found using two simple methods are presented. Finally, the main results as well as future work are discussed in the conclusion.

2 LITERATURE REVIEW

In this chapter, lake energy budget and stratification are presented. It is followed by a literature review covering lake surface temperature evaluation and the impacts of CC on water temperature.

2.1 LAKE ENERGY BUDGET AND STRATIFICATION

The temperature of a lake depends on the difference between incoming and outgoing energy. Primary inputs of energy come from downwelling shortwave radiation R_s (visible sunlight), and downwelling longwave radiation R_{Ld} (infrared). Depending on the surface albedo α (the proportion of light reflected by the surface), a fraction of the incoming shortwave (SW) radiation is reflected back to space (αR_s). The surface also emits longwave (LW) radiation (R_{Lu}) to the atmosphere as a function of its temperature and emissivity.

When the lake surface is warmer than the overlaying air layer, sensible heat (SH) is transferred from the lake to the atmosphere, and vice-versa when the lake is colder than air. The lake also loses heat when evaporation occurs at the surface (latent heat, LH). Other heat sources or losses include water inflow (Q_{in}) and outflow (Q_{out}), as well as ice formation and melt. Note that bottom sediments in shallow lakes can also store and release heat (Q_{sed}). All of these components are represented in Figure 1.

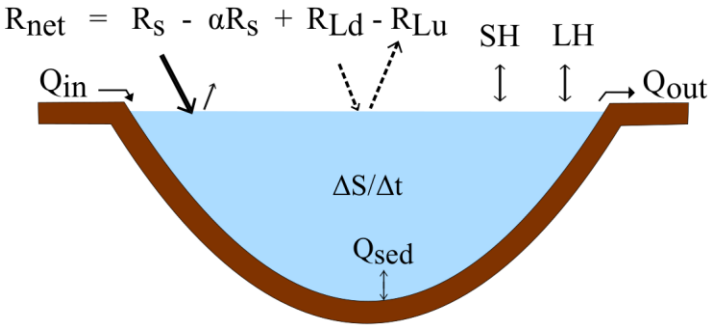

Figure 1. Components of a lake energy budget, adapted from Bailey et al. (1997). All terms are expressed in W m-2.

Lake Ontario waters undergo complete mixing twice a year, for that reason it is categorised as a dimictic lake. Throughout a year, four phases are usually observed in this kind of lake, a summer stratification, a fall overturn, a winter stratification and a spring overturn. In summer, three vertical layers can be distinguished in the lake: the epilimnion (i.e. mixed layer), the thermocline (or

metalimnion) and the hypolimnion. In the epilimnion, temperature is mostly constant with depth because of vigorous mixing mainly provoked by wind. The thermocline is a transition zone between the epilimnion and the hypolimnion, where water temperature decreases quickly with depth. When the lake is deep enough, one last section called the hypolimnion follows. The temperature in this section is independent of radiative heat inputs at the surface; therefore, water temperature is constant with depth (≈ 4°C). In fall, a complete mixing of the lake is observed when lake surface temperature (LST) decreases to maximum density temperature (4°C) — with a constant water density in the water column, the action of radiation and winds allow for a complete mixing of the lake (an overturn). As air cools and surface water temperature falls below 0°C, some ice forms on the lake surface and winter stratification is observed: the lake becomes almost isothermal. As the surface of the lake warms in spring, ice cover decreases. The difference in heating of the shallow and deep parts of the lake creates large scale convection cells, known as a thermal bar. Eventually, the water temperature reaches 4°C, another overturn is observed and the cycle starts over. Those phases are illustrated in Figure 2.

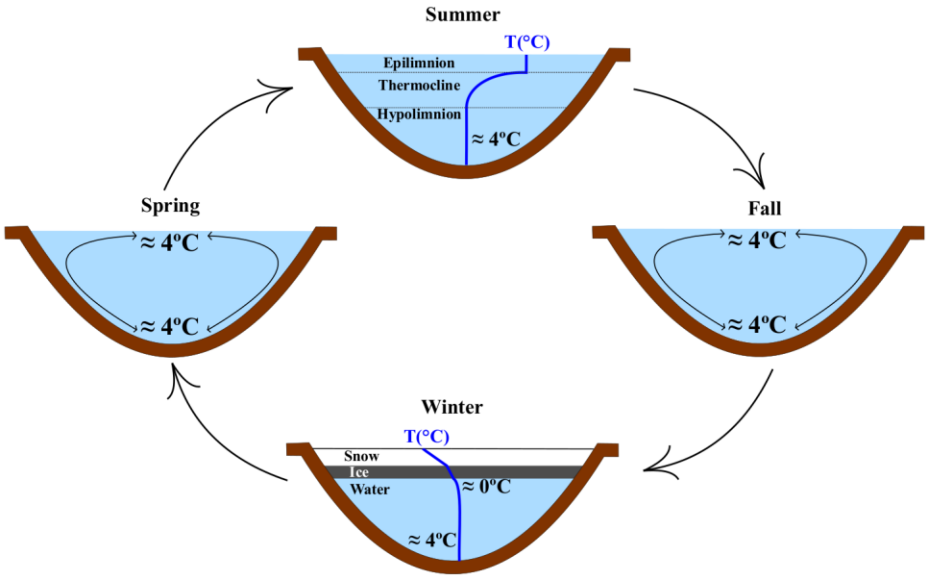

Figure 2. Typical mixing and stratification in dimictic lakes, adapted from Shaw et al. (2004).

2.2 EVALUATING LAKE SURFACE TEMPERATURE (LST)

Models that predict lake surface water temperature vary from simple empirical models to complex process-based models. Empirical relationships between observed lake surface temperature and observed air temperature have been developed for various time scales ranging from daily to annual.

On an annual scale, based on observations from 87 lakes in North America, Shuter et al. (1983) developed a statistical model that estimates annual means of LSTs from three proxies: LSTs during ice cover, maximum daily LST and numbers of ice-free days.

A common method to capture the seasonality in both water and air temperature consists of evaluating twelve monthly linear regressions from multi-year datasets. For example, observed water temperatures (Tw) for Lake Opeongo, Lake Mendota and South Bay (Ontario) were each expressed as a linear function of air temperature (Ta) (McCombie 1959). Depending on the lake, maximum slopes were found in June or July, when a 1°C increase in monthly Ta resulted in Tw increases ranging between 0.8-1.1°C (see Figure 3).

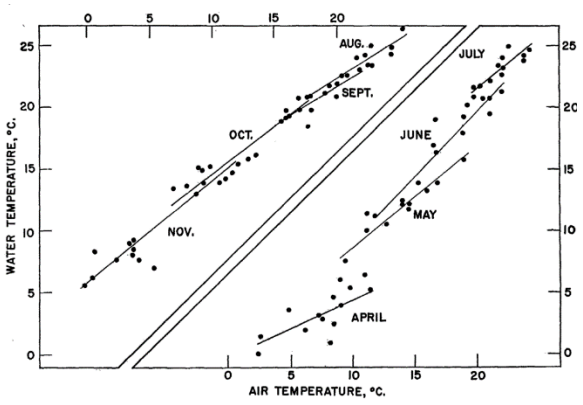

Figure 3. Relation between monthly air temperature and water temperature at Lake Mendota, taken from McCombie (1959).

On a sub-monthly scale, Kettle et al. (2004) created an empirical model that estimates summer daily lake temperature using air temperature, theoretical clear-sky solar radiation and lake size. The model was based on data from fifteen lakes located in southwest Greenland, with depths varying between 3.5 to 47 m. It was initially created to estimate LST at smaller than 24-hour time steps, for the period where water temperature exceeds 4°C. Matuszek and Shuter (1996) have also found an empirical equation applicable when LSTs are above 4°C. It evaluates daily LST from the day of the year (DOY) and the

averages of air temperature taken over the previous 5 and 15 days. While empirical models only necessitate few input data, they often lack representation of important processes occurring in lakes and at the water-atmosphere interface, such as the influence of wind-induced mixing or heat loss through evaporation. When using empirical models to forecast or hindcast water temperature, we thus implicitly assume that these phenomena do not stray far from their behavior over the calibration period.

More recently, Piccolroaz et al. (2013) and Toffolon et al. (2014) developed a semi-empirical model that predicts LST using continuous time series of daily air temperatures as input—the *air2water* model. Although this model is based on physical equations, it still needs to be calibrated from historical daily time series of air and water temperatures. Case studies over Lake Erie and Lake Superior have shown that the model performs very well; daily root mean square errors (RMSE) were under 1°C (Figure 4).

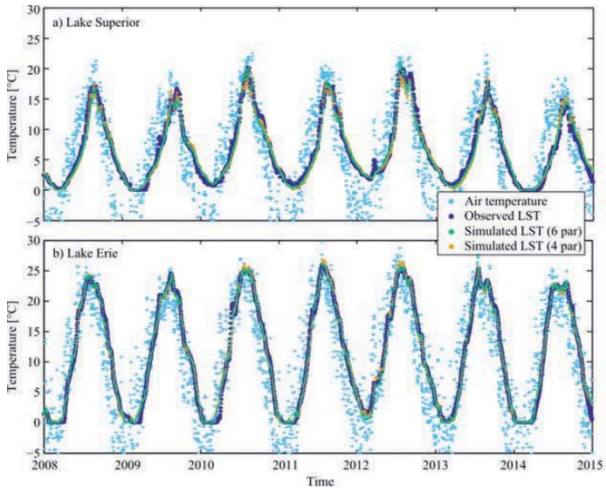

Figure 4. Observed air temperature (light blue dots), observed lake surface temperature (dark blue dots) and simulated LST using the air2water model with 6 and 4 parameters, taken from Piccolroaz (2016).

Considering its ability to implicitly represent the heat budget in lakes, the *air2water* model has been proposed by its authors as a good candidate for long-term projection of LST.

Another approach to evaluate lake surface temperatures consists in using process-based lake models, such as Flake (Gula and Richard Peltier 2012), Hostetler (Martynov et al. 2010) or 3D models like ELCOM (Hall 2008) or NEMO (Dupont et al. 2012). These models consider atmosphere-lake heat exchanges as well as heat transfer in the water column or the lake volume. To project

future LSTs using process-based lake models, they must be coupled to climate models or driven by time series derived from climate projections.

2.3 CLIMATE CHANGE AND LST

Climate change is expected to induce multiple changes to the Great Lakes hydrological and thermal regimes. Apart from increases of air temperature, apprehended changes include: a decrease in lake ice cover (e.g. Assel 2005; Wang et al. 2012), an increase in lake evaporation (e.g. Cohen 1986; Croley II 1990) and longer periods of summer lake stratification (e.g. McCormick and Fahnenstiel 1999; Austin and Colman 2007; Trumpickas et al. 2009). The evolution of annual ice cover averaged over the Great Lakes for the period 1973-2010 is presented in Figure 5.

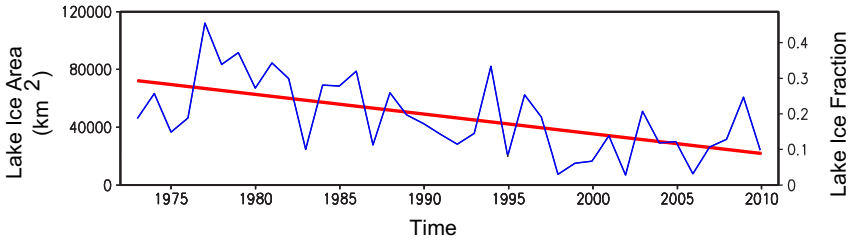

Figure 5. Mean annual ice cover averaged over all Great Lakes, adapted from Wang et al. (2012).

As can be seen from Figure 5, the Great Lakes ice area shows a negative trend over the 1973-2010 period. Significant downward trends were found over all lakes and were maximal at Lake Ontario, where a –2.3% yr^{-1} decrease in mean annual lake ice cover was observed.

The changes mentioned above favor a decrease in the Great Lake water levels. Observations of water level from 1860 to the present day are shown in Figure 6.

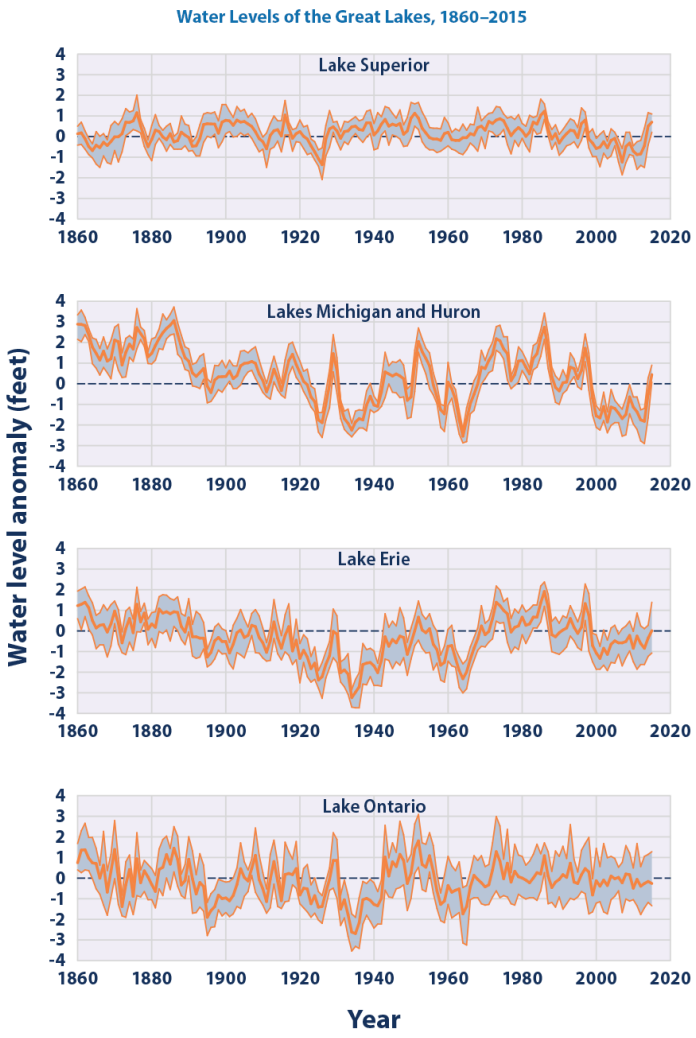

Figure 6. Great Lakes water level observations (NOAA, 2016).

Water levels in Lakes Michigan and Huron appear to have a negative trend from the 1920s. Most studies investigated future changes in the Great Lakes water resources through an analysis of the so-called net basin supply (NBS). Some of them have projected a future decrease in annual water supply to the Great Lakes (Croley II 1990; Hayhoe et al. 2010; Angel and Kunkel 2010), while others have reported the opposite or no change at all (e.g. Music et al. 2015). The differences in projected NBS changes are due to the discrepancies in the projected changes in runoff, lake evaporation and precipitation over the lakes.

To quantify changes on water temperature in the past, historical trends can be evaluated from long-term observations. Table 1 presents a summary of

historical trends as well as projected changes in lake temperature of the Great Lakes.

Table 1. Historical and projected changes in water temperature in the Great Lakes and Minnesota Lakes.

Historical change in lake temperature (°C yr^{-1})			
Lake	**Time period**	**Value**	**Reference**
Lake Superior	1906-1992 (near-shore)	+ 0.01	McCormick and Fahnenstiel (1999)
	1979-2006 (epilimnion)	+ 0.11	Austin and Colman (2007)
Lake Michigan	1979-2006 (epilimnion)	+ 0.065	Austin and Colman (2007)
Lake Huron	1979-2006 (epilimnion)	+ 0.086	Austin and Colman (2007)
Lake Erie	1918-1992 (near-shore)	+ 0.01	McCormick and Fahnenstiel (1999)
	1983-2002 (surface average)	+ 0.037	Burns et al (2005)
Lake Ontario	1985-2009 (epilimnion)	– 0.05	Schneider and Hook (2010)
	1995-2006 (surface average)	No significant change	Trumpickas et al. (2009)
Projected changes in lake temperature (°C)			
Lake	**Scenario**	**Value**	**Reference**
Lake Ontario	A2, B2 (2041-2070) (2071-2100)	1-5 (surface average)	Trumpickas et al. (2009)
	2 x CO_2	2-3 (deep water)	Boyce et al. (1993)
Minnesota Lakes	2 x CO_2	3-4 (annual maxima)	Stefan et al. (1998)
	2x CO_2	2°C (epilimnion)	Hondzo and Stefan (1993)

Adapted from Shimoda et al. (2011)

As can be seen from Table 1, observed water temperature shows a positive trend at almost all locations. It is interesting to note that Schneider and Hook (2010) have reported a downward trend in Lake Ontario summer (JAS) water temperature from satellite and buoy data. Many studies have shown that other lakes in the Great Lakes basin are warming at a faster rate than air temperature (e.g. Austin and Colman 2007; Austin and Colman 2008; Sharma et al. 2015). Due to the decrease of ice cover and to a longer summer

stratification period, the trend in Lake Superior water temperature anomaly is twice as large as the trend in regional air temperature (Austin and Colman 2007; Austin and Colman 2008; Trumpickas et al. 2009).

Several studies looked at the evolution of LST in a changing climate (e.g. Hondzo and Stefan 1993; Stefan et al. 1998; Piccolroaz 2013). For the scenario where the CO_2 concentration from period 1961-1979 is doubled, Minnesota lakes water temperature maxima were projected to increase by 3 to 4°C, while winter water temperature were not significantly affected (Stefan et al. 1998). They compared water surface temperature modelled by a 1D lake model driven with observations (for the historical climate) and driven with outputs from a Global Climate Model (for future climate). Using a similar methodology but different reference period, Hondzo and Stefan (1993) found changes in epilimnion temperature of approximately 2°C (same location). Also using a $2xCO_2$ scenario and a 1D thermodynamic lake model, Boyce et al. (1993) estimated that Lake Ontario deep waters would warm by 2-3 °C in the future climate.

Trumpickas et al. (2009) evaluated mid and long-term changes in the Great Lakes water temperature. In this study, the annual cycle of open-water temperature was parametrized by three distinct stages: an increasing linear function in spring, a plateau in summer (T_{max}) and a decreasing linear function in fall. This cycle is illustrated in Figure 7.

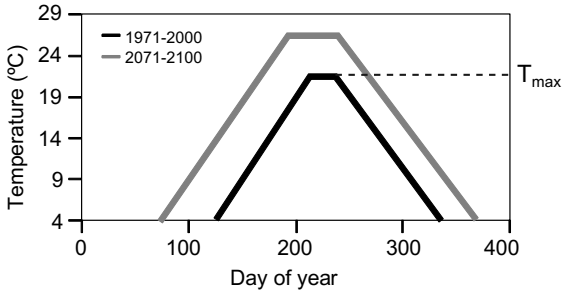

Figure 7. Lake Ontario open water temperature cycle for the period 1971-2000 (black) and the period 2071-2100 (grey) under scenario A2, adapted from Trumpickas et al. (2009).

Spring and fall slopes as well as the relationship between T_{max} and air temperature were calculated from observations. Changes on air temperature were projected considering A2 and B2 emission scenarios, which correspond to CO_2 concentrations that are 3.5 and 1.5 times greater than those observed in 2000. Using air temperature projections from a Global Climate model (GCM) and assuming that the regression and the slopes are stationary, the changes

in open water lake temperature were projected. The results for Lake Ontario are presented in Table 2. T_{max} is the twentieth highest temperature observed for a year. $J10_{spring}$ and $J10_{fall}$ are the DOY when water surface temperature reaches 10°C in spring and in fall.

Table 2. Projected Tmax, J10spring and J10fall under A2 and B2 scenarios for Lake Ontario, adapted from Trumpickas et al. (2009).

Time period	Scenario	T_{max} (°C)	ΔT_{max} (°C)	$J10_{spring}$ (DOY)	Δ $J10_{spring}$ (DOY)	$J10_{fall}$ (DOY)	Δ $J10_{fall}$ (DOY)
1971-2000	Norm	21.6		152.7		302.0	
2011-2040	A2	23.0	+ 1.4	142.7	– 10.0	308.0	+ 6.9
2011-2040	B2	22.9	+ 1.3	140.4	– 12.2	309.0	+ 7.0
2041-2070	A2	24.1	+ 2.5	127.1	– 25.6	320.2	+ 18.2
2041-2070	B2	23.8	+ 2.2	131.4	– 21.3	316.8	+ 14.8
2071-2100	A2	26.4	+ 4.8	106.2	– 46.5	332.7	+ 30.7
2071-2100	B2	24.8	+ 3.2	122.0	– 30.7	325.7	+ 23.7

Basically, their results indicate an increase of both T_{max} and stratification period in the future.

To the best of our knowledge, no study has yet used a large ensemble of climate projections to evaluate changes in lake surface temperatures. The main limitation of using this technique lies in the very high computational cost required to generate a large ensemble of simulations. Another important limitation is a very poor representation of inland lakes in GCMs. In most of them, the Great Lakes are not even seen; in that case, the grid points that should be represented as lakes are actually resolved as if they were land. When water points are present, LSTs are usually approximated using an interpolation of Atlantic and Pacific Ocean temperatures, which induces large errors. Fortunately, the Great Lakes are incorporated in some Regional Climate Models and are modeled as oceans in some Global Climate Models.

3 DATA AND METHODOLOGY

The following sections describe datasets used in this study as well as the techniques used to project future lake surface temperatures.

3.1 DATASETS

Several observed and simulated datasets of air and water temperature (Ta and Tw) were available for this study. Measurement locations are shown in Figure 8.

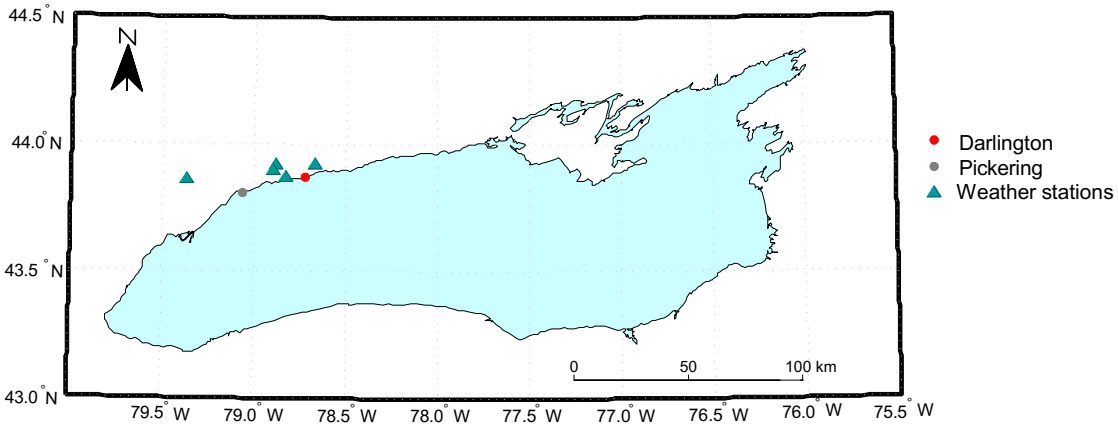

Figure 8. Location of Darlington (red dot) and Pickering (grey dot) nuclear power plants as well as Environment and Climate Change Canada weather stations (green triangles).

3.1.1 OBSERVATIONS

Water intake temperatures measured at Darlington Nuclear Power Station (DNPS) and at Pickering were available. Since time series of DNPS were much longer (1991-2015), we based our analysis on this dataset.

Table 3. Characteristics of provided water temperature datasets.

	Pickering A (PA)	Pickering B (PB)	Darlington
Period	2007-2015 (no data for 2013)	2007-2015	1991-2015
Time step	Hourly	Hourly	Daily
Intake	Near shore	Near shore	Into the lake (≈ 1km from the shore)

To complement the analysis, we also used time series of summer lake surface temperature available from the Global Lake Database (GLD, Sharma et al. (2015)). This dataset provides bulk lake water skin (water-air interface) temperatures derived from satellite observations covering the period 1991-2009.

Available observed 2-meter air temperatures from Environment and Climate Change Canada weather stations were relatively sparse and contained multiple gaps. For that reason, we averaged observations from five nearby weather stations (Table 4) and from one grid point in a gridded air temperature dataset made available by Natural Resources Canada (NRCan).

Table 4. Description of weather stations from ECCC network.

	Oshawa WPCP	Oshawa	Whitby Mueller	Toronto Buttonville A	Bowmanville Moster
Location	43.87°N, 78.83°O	43.92°N, 78.88°O	43.90°N, 78.90°O	43.86°N, 79.37°O	43.92°N, 78.67°O
Period	1991-2016	2010-2016	2001-2006	1991-2015	1991-2002
Time step	Daily				
Climate ID	6155878	6155875	6155870	615HMAK	6150830

The NRCan gridded air-temperature dataset (McKenney et al. 2011) is based on observations from the weather station network of Environment and Climate Change Canada (ECCC). The raw data is interpolated on a 10km x 10km grid across Canada. We evaluate mean daily air temperature by averaging daily maximum and daily minimum temperatures. Interannual cycles of air temperature from each dataset are represented in Figure 9.

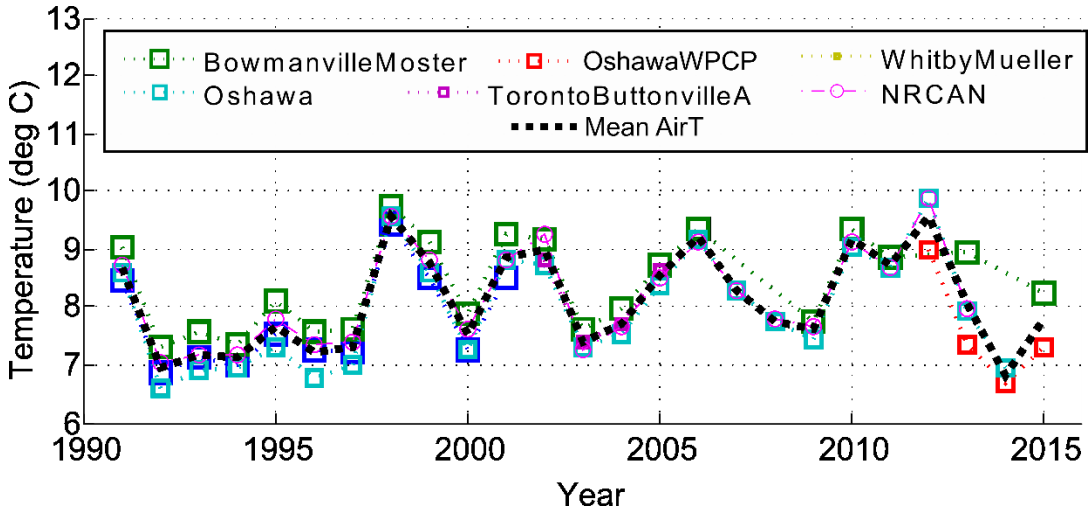

Figure 9. Interannual cycle of 2-m air temperature from multiple datasets.

3.1.2 CLIMATE CHANGE ASSESSMENT DATA

When performing a climate change assessment study, the objective of using climate models is to simulate the expected response of the climate system to future increases of greenhouse gas (GHG) concentrations. GHGs absorb longwave infrared radiation emitted by the surface. While some part of the infrared is re-emitted toward space and sheds energy off the Earth, part of it is reemitted towards the surface. When GHG concentration increases, more infrared is re-emitted back to Earth and less energy escapes into space — this is often referred to as GHG radiative forcing.

To evaluate the climate impact of this radiative forcing, future GHG concentrations are imposed to climate models and simulations are generated with these configurations. Since future greenhouse gas concentrations are impossible to predict with precision, a range of plausible emissions scenarios are developed depending on factors such as future population, technological development and political choices. Those used in the last Intergovernmental Panel on Climate Change (IPCC) assessment report (AR5) are presented in Table 5.

Table 5. Representative Concentration Pathways, adapted from Moss et al. (2010). The radiative forcing column indicates the approximate surplus energy flux that accumulates in 2100 due to GHGs; the CO2 equivalent indicates the concentration of GHGs in the atmosphere, and the pathway describes the emission trajectory.

Scenario	Radiative forcing	CO_2 equivalent (p.p.m.)	Pathway
RCP8.5	> 8.5 W m^{-2}	> 1 370 in 2100	Rising
RCP6.0	~6 W m^{-2}	~850 at stabilisation after 2100	Stabilisation without overshoot
RCP4.5	~4.5 W m^{-2}	~650 at stabilisation after 2100	Stabilisation without overshoot
RCP2.6	Peak at ~3 W m^{-2} before 2100 and then declines	Peak at ~490 CO2-equiv. before 2100 and then declines	Peak and decline

These scenarios describe Representative Concentration Pathways (RCP) of greenhouse gas emissions. Each scenario is named after the radiative forcing expected in 2100 (Figure 10). In this study, RCP4.5 and RCP8.5 scenarios were used.

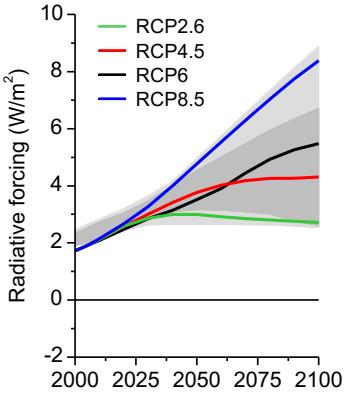

Figure 10. Changes in radiative forcing, adapted from van Vuuren et al. (2011).

3.1.2.1 Climate models

A climate model is defined as a "numerical representation of the climate system based on the physical, chemical and biological properties of its components, their interactions and feedback processes, and accounting for some of its known properties" (IPCC 2013). The atmospheric module of climate models consists of a set of nonlinear differential equations based on fundamental physical laws, which are numerically solved and provides information of various atmospheric variables on multiple grid points in the

atmosphere. These variables include for example: air temperature, pressure and moisture. To represent the processes occurring at Earth's surface, different modules representing different surface types (land, lakes, ocean, glacier and urban areas) are coupled to the atmospheric model—they exchange relevant quantities at all calculation time steps. A climate model that covers the entire planet is a Global Climate Model (GCM) and one that covers a specific area of the planet (a continent for example) is a Regional Climate Model (RCM). Current typical spatial resolutions of GCMs are in the order of 150-250 km, while RCMs have 25-50 km, reaching 12 km in some cases (e.g., EURO-CORDEX over Europe).

Since regional climate models concentrate on a specific area of the planet, they need information from outside their domain. This is obtained with lateral boundary conditions provided on the grid points surrounding the domain. To project future climate with RCMs, lateral boundary conditions are taken from GCMs. They include for example, multi-level air temperature, horizontal winds and humidity. Using data from global climate models to drive regional climate models is called dynamical downscaling.

For this study we use an ensemble of several regional climate simulations generated within the Coordinated Regional Climate Downscaling Experiment (CORDEX; Giorgi et al. (2009)) over North America. These are supplemented with simulations generated with the Canadian Regional Climate Model (CRCM5; Šeparović et al. (2013), Martynov et al. (2013)) by Ouranos Climate Simulation and Analysis group (referred to as CRCM5-Ouranos). The RCMs that were considered are listed in the Annex. Spatial resolutions of RCM outputs from this ensemble are of 50 km and 25 km.

3.1.2.2 Uncertainty in climate projections

Climate projections are subjected to three principal uncertainties: the chaotic nature of the climate system (natural variability), the formulation of climate models and future atmospheric concentration of greenhouse gases (emission scenario).

To account for these three uncertainties, an ensemble approach is often used. Considering projections from multiple climate models aims to capture the range of uncertainty due to climate natural variability and to the differences in the formulation of each climate model. To capture the range of uncertainty related to future GHG emissions concentration, multiple emission scenarios are considered. We end up with a large ensemble of projections, from which we

can evaluate an ensemble mean as well as the 25th and 75th percentiles for example. The ensemble mean gives an idea of the general trend and the range between the 75th and 25th percentile can be used as an indicator of the uncertainty.

3.2 TWO METHODS TO PROJECT FUTURE WATER TEMPERATURE

Here we use two simple approaches to evaluate future lake water temperatures. The first one is a simple regression between air temperature (Ta) and water temperature (Tw). The second one uses a simple model called *air2water* that takes into account lake physical characteristics and physical processes.

3.2.1 FIRST METHOD – LINEAR REGRESSION

The first method consists of evaluating future water temperature knowing the relationship between historical Ta and Tw. This method consists in three steps as follows:

1) *Evaluate the relationship between historical Ta and Tw*

We look for relationships at annual and seasonal time scales, more specifically for summer, as it is the period when water temperature is the warmest. The summer period was defined as the three months when water temperature reaches its highest value: July, August and September (JAS).

2) *Evaluate the change in Ta from regional climate projections*

We consider changes in air temperature interpolated at the location of Darlington Nuclear Power Station. From regional climate model outputs, temporal averages of air temperature are computed for a reference period (1986-2015) and a future period (2041-2070), and the difference between both periods is calculated (delta). One delta is calculated for each season (JAS, OND, JFM and AMJ). The 30-year future time window was chosen to be comparable in length to the reference period.

Table 6. Equation and time window of components used in climate change assessment studies. Data taken from climate models is indicated in bold.

Variable	Equation	Time window
Observations	obs	1991-2015
Reference	**ref**	**1986-2015**
Future	**fut**	**2041-2070**
Delta (Δ)	**fut – ref**	**(2041-2070) – (1986-2015)**
Perturbed	obs + **Δ**	2041-2070

To capture the essence of the physical phenomena, climate models simulate the climate system by application of assumptions to the basic fundamental laws of physics. To produce data on grid points, because of limited computation resources, they use parameterizations for representation of sub-grid scale processes (that occur at a smaller scale than the model grids). The simulated climate system is therefore different from the observed reality due to model biases and differences in spatial scales between the observations (local station) and the model (grid). In the scientific community, because of the lack of information on the future, we assume that the biases from the future and the reference periods are comparable, and thus will mostly cancel each other when their difference (delta) is evaluated.

3) *Evaluate the change in Tw using the relationship established in 1) and the projected Ta found in 2)*

Finally, we apply the change in air temperature (delta computed in 2) to the observed air temperature record. By using the relationship found in 1), we can estimate the future water temperature. The observed temperature comes from five nearby weather stations and one grid point from the NRCan gridded dataset (as explained in Section 3.1.1). Applying a delta from climate models to historical observations is one among many downscaling methods available, which is commonly known as the 'perturbed' method (Table 6).

3.2.2 SECOND METHOD – *AIR2WATER* MODELING

We use the *air2water* model to project LSTs in the future (Piccolroaz et al. 2013; Toffolon et al. 2014). The *air2water* has three different formulations: with 8, 6 and 4 parameters. For this report, we chose the formulation of the model that uses 6 parameters. The equation that evaluates lake surface

temperature (T_w) from air temperature (T_a) is based on the energy budget of the well-mixed part of the lake (Eq. 1 and Eq. 2):

$$\frac{dT_w}{dt} = \frac{1}{\delta}\left\{a_1 + a_2 T_a - a_3 T_w + a_5 \cos\left[2\pi\left(\frac{t}{t_y} - a_6\right)\right]\right\} \quad \text{Eq.1}$$

where

$$\begin{cases} \delta = \exp\left(-\frac{T_w - T_h}{a_4}\right) & \text{for } T_w \geq T_h \\ \delta = 1 & \text{for } T_w < T_h \end{cases} \quad \text{Eq.2}$$

In the equations above, *t* represents time, d*t* the chosen time step, T_h the water temperature at which the well-mixed depth of the lake is maximal (4°C for dimictic lakes) and t_y the number of time steps in a year. For example, if d*t* = 1 month, then t_y = 12 and if d*t* = 1 week, then t_y = 52.

Each parameter has a physical signification. The annual water temperature cycle is parametrized as a cosine function whose amplitude correspond to coefficient a_5 and period depends on coefficient a_6. Coefficients a_2 and a_3 represent processes that depend on T_a and T_w, such as transfers of sensible and latent heat. Coefficient a_4 indicates the strength of the lake stratification when water is warmer than 4°C and coefficient a_1 is a residual term.

Note that this model is only valid for lake surface temperatures, thus the effect of different mixing processes occurring deeper into the lake, such as the formation of a thermal bar, upwellings and horizontal currents, are not included in the model. Other processes impacting the heat content of the lake that are not correlated to air temperature are also not represented (like advected heat, referred to as Q_{in} and Q_{out} in section 2.1).

Using the water intake temperature measured at the Darlington Nuclear Power Station (DNPS), and the corresponding observed air temperature, we calibrate the model over the observation period. Once the six parameters are evaluated, a reference water temperature time series is generated by the model. Then, we drive the *air2water* model using perturbed daily air temperature time series. This perturbed air temperature is calculated by adding seasonal air temperature deltas found in the first method to the historical air temperature time series. This way, the *air2water* model provides time series of future water temperature.

4 RESULTS AND DISCUSSION

In this final section, results for the observations as well as the projected water temperatures obtained from both methods are presented.

4.1 OBSERVATIONS

4.1.1 ANNUAL

With a few notable exceptions (2000, 2004), annual water temperatures measured at Darlington track annual air temperatures (Figure 11). A perfect match between both series is not expected because the two variables respond differently to incident radiation, and fluxes of heat between air and water depend on multiple factors, including ice cover, winds, humidity and mixing. In other words, a particularly cold year does not automatically imply that water temperatures will be particularly cold that year.

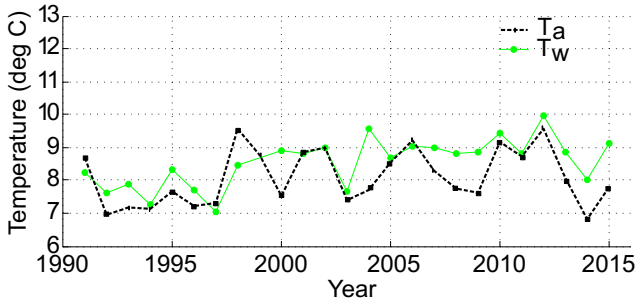

Figure 11. Annual series of observed air (black) and water (green) temperatures for the Darlington site. Since over 40% of the water temperature data in 1999 was missing, that year was removed from the annual analysis.

Since mean water temperature is above 4°C, we can assume that the Darlington intake site is located above the hypolimnion, probably somewhere in the thermocline. Some statistics of both time series are presented in Table 7.

Table 7. Statistics of annual observed air and water temperature over 1991-2015.

Statistic	Ta	Tw
Mean (°C)	8.5	8.1
Standard deviation (°C)	0.8	0.7
Presence of a trend	No	Yes

As expected, water that is withdrawn at depth has slightly lower temperature than air and shows lower interannual variability, thus smaller standard deviation (Table 7). Note that a Mann-Kendall test confirmed the presence of a monotonic trend in the water temperature dataset only.

4.1.2 SUMMER

No water temperature data was available from the Global Lake Database (GLD) for the summers of 1992 and those of 2010 to 2015. From the Darlington site, over 40% of daily water temperature data was missing in July 1999. For these reason, these summers were excluded from this subsection. Annual series of summer temperatures and anomalies are presented in Figure 12.

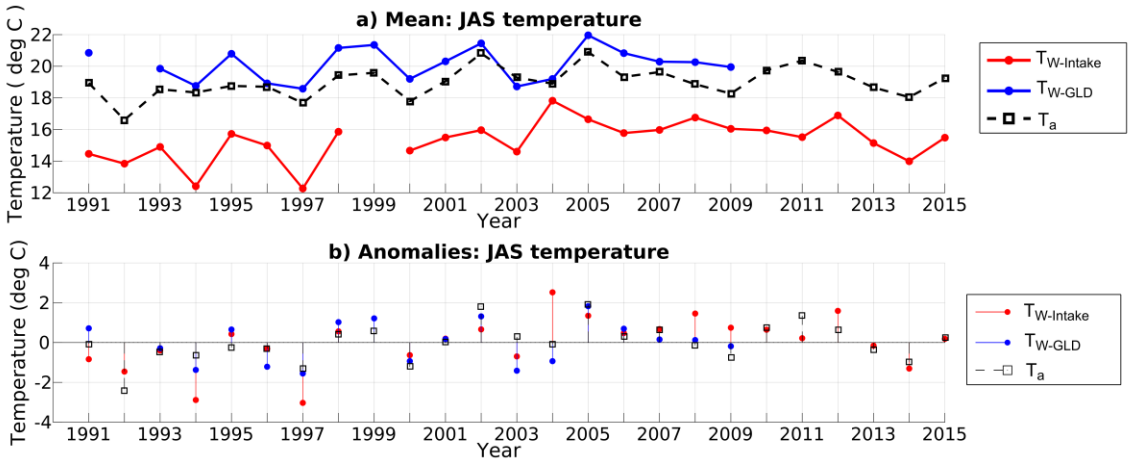

Figure 12. Annual series of summer a) mean air (black), intake (red) and lake surface (blue) temperature and b) anomalies in air (black), intake (red) and lake surface (blue) temperatures, with regard to the available data of each time series.

Even if water from the Darlington intake is cooler than surface water and air temperature, they display similar annual variability. Summer water surface temperature from the Global Lake Database (GLD) is slightly higher than air temperature, which is representative of the Great Lakes thermal regimes in that season. Some statistics of the three time series are presented in Table 8.

Table 8. Statistics of summer observed air as well as Darlington intake and surface water temperature.

Statistic	**Ta (1991-2015)**	**Tw Intake (1991-2015)**	**Tw Surface GLD (1991-2009)**
Mean (°C)	19.1	15.3	20.6
Standard deviation (°C)	0.9	1.0	1.3
Presence of a trend	No	No	Yes

An upward trend was detected in the GLD time series using the Mann-Kendall test.

4.2 DIFFERENCES BETWEEN SIMULATIONS

All available simulations from CORDEX-NA (https://na-cordex.org/) were used in this study. Air temperature is interpolated linearly at the location of Darlington nuclear power station.

Projected changes in annual precipitation and temperature are shown in Figure 13.

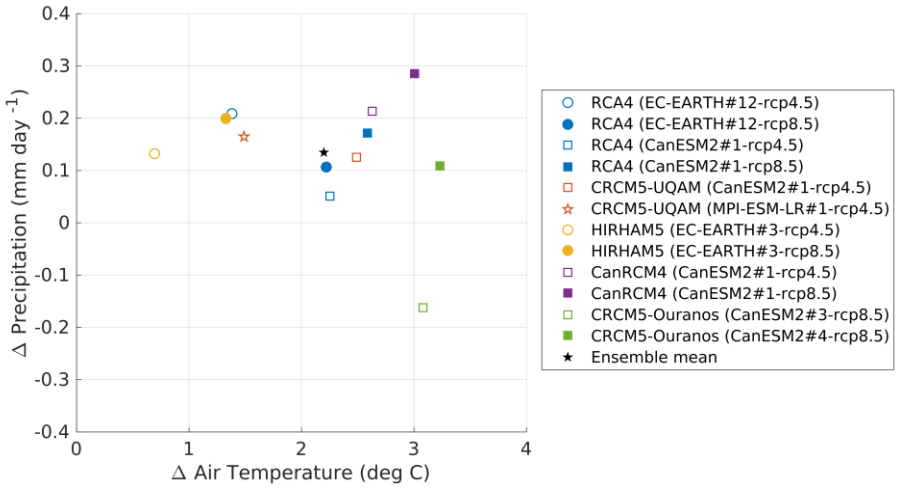

Figure 13. Projected change in annual precipitation versus change in annual air temperature for each simulation of the ensemble. Deltas were calculated by subtracting long-term averages of reference values (1986-2015) from future values (2041-2070). Each simulation is identified as: RCM (driving GCM) and future emission scenario.

As can be seen from Figure 13, all models project an increase in air temperature at the 2041-2070 horizon. This warming ranges between 0.7-3.2°C, depending on the simulation. All simulations, but one, project an increase of annual precipitation between 0.05 and 0.3 mm day^{-1}.

4.3 AIR TEMPERATURE PROJECTIONS

In total, twelve Regional Climate Simulations (RCM) were available for this study: six projections use the RCP4.5 future GHG emission scenario and six use RCP8.5 (see Table A, Annex A). Since we are using a small sample, we choose a simple equation to evaluate percentiles (P) in our ensemble (Eq. 3):

$$P = 100 \times \frac{n - 0.5}{N} \qquad \text{Eq. 3}$$

Where n represents the rank of the value (when the sample is sorted in ascending order) and N is the size of the sample.

4.3.1 ANNUAL

Projections of annual air temperature are presented in Table 9.

Table 9. Description of Regional Climate Simulations used in this study with their corresponding emission scenario (RCP), annual air temperature in the reference (1986-2015) and future period (2041-2070), deltas (2041-2070 minus 1986-2015) as well as percentile of each delta. RCMs are listed in ascending order of their deltas for the Darlington site.

RCM (driving GCM)	RCP	Reference Ta (°C)	Future Ta (°C)	Delta Ta (°C)	Percentile of the Delta
HIRHAM5 (EC-EARTH#3)	4.5	6.1	6.8	0.7	4
HIRHAM5 (EC-EARTH#3)	8.5	6.1	7.4	1.3	13
RCA4 (EC-EARTH#12)	4.5	9.5	10.9	1.4	21
CRCM5-UQAM (MPI-ESM-LR#1)	4.5	7.4	8.9	1.5	29
RCA4 (EC-EARTH#12)	8.5	9.6	11.8	2.2	38
RCA4 (CanESM2#1)	4.5	11.3	13.5	2.3	46
CRCM5-UQAM (CanESM2#1)	4.5	10.0	12.4	2.5	54
RCA4 (CanESM2#1)	8.5	11.5	14.1	2.6	63
CanRCM4 (CanESM2#1)	4.5	9.6	12.2	2.6	71
CanRCM4 (CanESM2#1)	8.5	9.8	12.8	3.0	79
CRCM5-Ouranos (CanESM2#3)	8.5	10.7	13.8	3.1	88
CRCM5-Ouranos (CanESM2#4)	8.5	10.5	13.8	3.2	96

Annual air temperatures from reference and future periods, as well as deltas vary considerably from one RCM to another, in relation with modelling uncertainties (different driving GCMs and RCMs) and natural variability. The effect of natural climate variability can be evaluated by comparing the two CRCM5-Ouranos runs (driven by two different members of CanESM2). The

differences in radiative forcing from emission scenario RCP4.5 and RCP8.5 during the 2041-2070 period (Figure 10) are also responsible for some of the differences seen in the deltas. For example, the difference between air temperature deltas evaluated from RCP8.5 and RCP4.5 emission scenarios is of 0.6°C for the HIRHAM5 regional climate model.

4.3.2 SUMMER

Projections of summer air temperature are presented in Table 10.

Table 10. Description of Regional Climate Simulations used in this study with their corresponding emission scenario (RCP), summer air temperature in the reference (1986-2015) and future period (2041-2070), deltas (2041-2070 minus 1986-2015) as well as percentile of each delta. RCMs are listed in ascending order of their deltas for the Darlington site.

RCM (driving GCM)	RCP	Reference Ta (°C)	Future Ta (°C)	Delta Ta (°C)	Percentile of the Delta
HIRHAM5 (EC-EARTH#3)	4.5	13.3	14.0	0.7	4
HIRHAM5 (EC-EARTH#3)	8.5	13.3	14.3	1.0	13
RCA4 (EC-EARTH#12)	4.5	19.9	21.1	1.2	21
CRCM5-UQAM (MPI-ESM-LR#1)	4.5	18.3	20.1	1.8	29
RCA4 (EC-EARTH#12)	8.5	19.9	22.1	2.3	38
RCA4 (CanESM2#1)	4.5	21.9	24.5	2.6	46
CanRCM4 (CanESM2#1)	4.5	20.4	23.2	2.8	54
CRCM5-UQAM (CanESM2#1)	4.5	21.2	24.1	2.9	63
RCA4 (CanESM2#1)	8.5	22.3	25.5	3.3	71
CanRCM4 (CanESM2#1)	8.5	20.7	24.1	3.4	79
CRCM5-Ouranos (CanESM2#4)	8.5	21.7	25.3	3.5	88
CRCM5-Ouranos (CanESM2#3)	8.5	21.4	25.3	3.9	96

As for the annual case, summer deltas vary considerably from one RCM to another. From the deltas presented in the two tables above, we can evaluate an ensemble mean and an uncertainty range.

4.4 FIRST METHOD – LINEAR REGRESSION

4.4.1 ANNUAL

Anomalies in annual air and water temperature are presented in Figure 14.

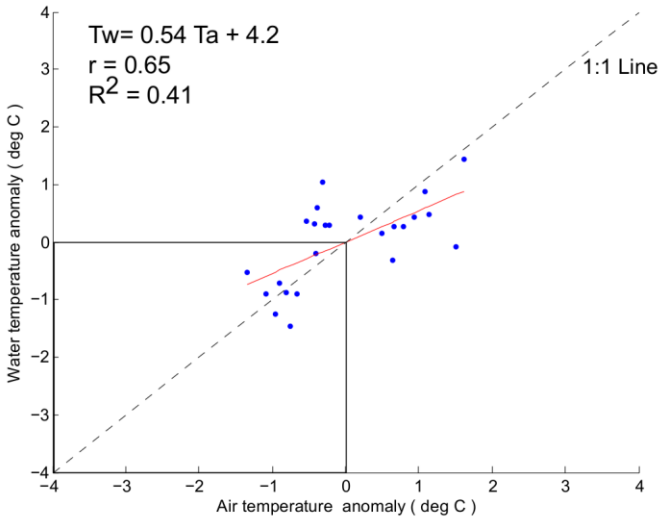

Figure 14. Anomalies in annual air temperature versus anomalies in annual water temperature, with regard to the 1991-2015 period, for the Darlington site. Symbols r and R^2 represent correlation and the coefficient of determination, respectively.

Annual anomalies in Ta and Tw for the 1991-2015 period are positively correlated. Air temperature is responsible for 41% of the variance in Tw. Note that Ta and Tw at Pickering A and Pickering B were much more correlated: r = 0.89 at PA and r = 0.95 at PB. Since the part of the lake more closely coupled to daily energy inputs is located close to its surface, one should expect near shore water temperature to be more correlated to Ta than water temperature measured deeper into the lake. In cooler years, water temperature shows larger departure from the linear regression. These discrepancies could be explained by more important ice cover and shorter stratification periods. Projected changes in air and water temperature are presented in Table 11.

Table 11. Observed, deltas and perturbed annual air temperature (Ta) and intake temperature (Tw) from the first method for the Darlington site.

	Ta (°C)			Tw (°C)		
Period	**Observed**	**Δ**	**Perturbed**	**Observed**	**Δ**	**Perturbed**
Ensemble mean	8.5	2.2	10.7	8.1	1.2	9.3
25th percentile		1.4	9.9		0.8	8.9
75th percentile		2.8	11.3		1.5	9.6

From the RCM air temperature ensemble (Table 9), we find that the difference between the ensemble mean from the future and reference period is of 2.2°C at the annual scale. This translates into an average annual increase of water temperature of 1.2°C and associated uncertainty range of 0.8-1.5°C.

4.4.2 SUMMER

Anomalies in summer air and water temperature are presented in Figure 15.

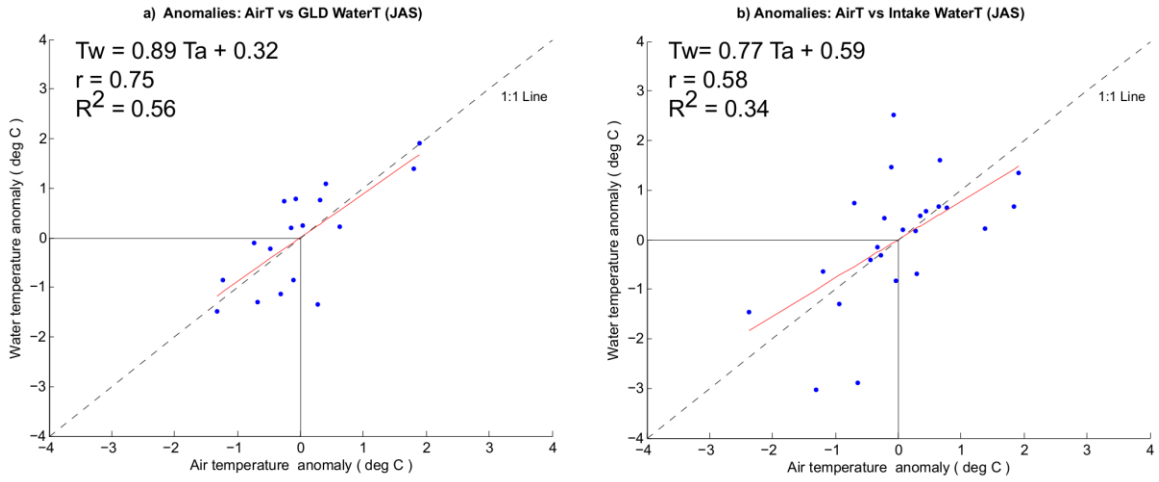

Figure 15. Anomalies in summer air temperature versus anomalies in summer water temperature, from a) the Global Lake database (GLD) with regard to the 1991-2009 period, and from b) Darlington intake with regard to the 1991-2015 period.

As expected, air temperature is more correlated to LST than to intake temperatures: Ta explains 56% of the variance of GLD water temperature versus 34% at the intake. Compared to slopes found in the annual analysis, higher ones are observed for summer period when the coupling between the lake and the atmosphere is stronger. Changes in water temperature are presented in Table 12.

Table 12. Observed, deltas and perturbed summer air temperature (Ta) and intake temperature (Tw) from the first method for the Darlington site.

	Ta (°C)			Tw (°C)		
Period	**Observed**	**Δ**	**Perturbed**	**Observed**	**Δ**	**Perturbed**
Ensemble mean	19.1	2.5	21.6	15.3	1.9	17.2
25th percentile		1.5	20.6		1.2	16.5
75th percentile		3.3	22.4		2.6	17.9

An average increase of summer water temperature of 1.9°C and associated uncertainty range of 1.2-2.6°C are projected at the 2041-2070 horizon.

4.5 SECOND METHOD – AIR2WATER MODELING

The *air2water* model was calibrated using observations of air and water temperature over the 1991-2005 period at the Darlington site and validated over the 2006-2015 period. During calibration, the Nash-Sutcliffe Efficiency Index was used as the objective function.

The parameter values obtained by calibration are presented in Table 13.

Table 13. Parameters obtained by calibration of the air2water model over the 1991-2005 period for the Darlington site.

Parameter	**a_1**	**a_2**	**a_3**	**a_4**	**a_5**	**a_6**
Value	0.7	0.04	0.1	5.1	0.4	0.7

The correspondence between observed and simulated water temperature for the validation period (2006-2015) are shown in Figure 16.

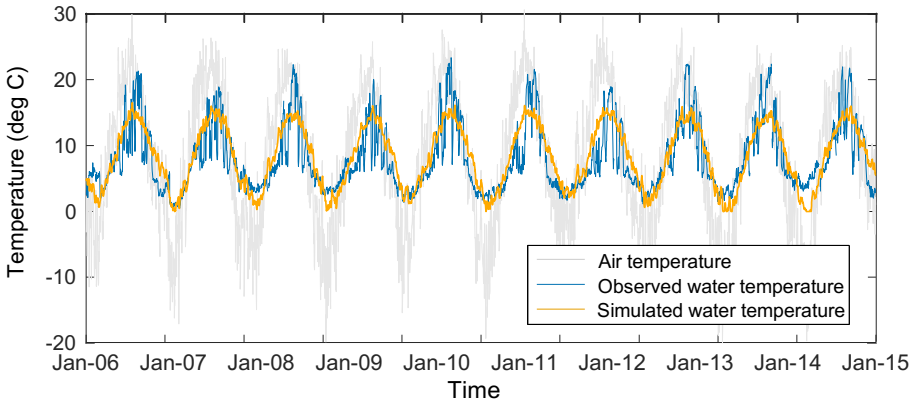

Figure 16. Daily observed air temperature (in grey), daily observed water temperature (in blue) and daily water temperature simulated by the air2water model (in yellow) for the period 2006-2015, at the Darlington site.

The *air2water* model underestimates August water temperatures by 2.4°C. However, this has little impact on JAS and annual mean temperatures (the bias is below 0.4°C for both periods). Since observed and simulated water temperatures are strongly correlated (r = 0.81) and since the differences in the mean of the two time series are not large, we can consider that the *air2water* model has an acceptable performance. As expected, due to the thermal inertia of large water bodies, air temperature displays much stronger day-to-day fluctuations compared to simulated and observed water temperature (Figure 16). Also as expected, observed water temperature has stronger variability than simulated water temperature. As previously mentioned, horizontal currents that can occur below the surface are not included in the formulation of the model, since they are not directly driven by air temperature. This is particularly observable in spring, when the formation of a thermal bar could cause additional mixing near the intake.

4.5.1 ANNUAL

Table 14. Observed, deltas and perturbed annual intake temperature (Tw) from the second method for the Darlington site.

Period	Observed Tw (°C)	ΔTw (°C)	Perturbed Tw (°C)
Ensemble mean	8.1	0.8	8.9
25th percentile		0.5	8.6
75th percentile		1.0	9.1

The projected annual warming of intake water temperature (Tw) obtained through the second method is smaller than the one obtained in the first method. This appears reasonable, since the first method is not as physically-based and doesn't capture the influence of the redistribution of the additional energy in the thermally-active volume of the lake.

4.5.2 SUMMER

Table 15. Observed, deltas and perturbed summer intake temperature (Tw) from the second method for the Darlington site.

Period	Observed Tw (°C)	ΔTw (°C)	Perturbed Tw (°C)
Ensemble mean	15.3	0.9	16.2
25th percentile		0.5	15.8
75th percentile		1.2	16.5

Although seasonal deltas were applied to the observations, rather than annual deltas, the warming projected in summer for intake water temperature (Tw) is

similar to the warming projected at the annual time-scale. This could be explained by the small variability of ΔTa from one season to another. In fact, the standard deviation of seasonal ΔTa ranges between 0.2 and 0.6°C depending on the simulation. Important thermal inertia of water bodies is reflected in the even smaller variability of ΔTw.

The results from the first and the second methods are summarized in Figure A in the Annex.

5 CONCLUSIONS

In this study, we used two methods to project changes in intake temperature at the Darlington Nuclear Power Station (DNPS) site at the 2041-2070 horizon. The twelve regional climate simulations (RCMs) used in this study all point towards an increase of air and water temperature. Larger increases in water temperature are found using the linear regression than the *air2water* model. Also, larger discrepancy and therefore uncertainty in projected summer water temperature was found for the linear regression model, which is not as physically-based as the one with the *air2water* model.

For future work, a different approach could be used when projecting water temperature with the *air2water* model. For example, the *air2water* model could be calibrated with lake surface temperature rather than temperature measured deeper into the lake. This should improve the performance of the model in simulating not only annual and seasonal mean temperatures, but also maximum and minimum water temperature. After this calibration, surface water temperature could be projected using bias-corrected air temperature from RCMs rather than delta-adjusted observations. This way, the *air2water* model would run with a dataset that is not so close to the one used for its calibration. It is expected that this approach will lead to a higher sensitivity of the *air2water* model with regards to the increasing air temperature. After projecting future lake surface temperatures, it should be possible to evaluate future intake water temperature using the newly-established relationship between surface and intake water temperatures.

An additional approach could be considered in future analyses through the evaluation of changes in mixed layer temperature simulated from lake or ocean models that are coupled to RCMs or GCMs.

Looking at long-term water temperature changes (2070-2100 horizon for example) could also be an interesting option if it applies to OPG's planning horizon.

ANNEX A. SUPPLEMENTARY MATERIAL

A.1. REGIONAL CLIMATE MODELS USED IN THIS STUDY

Table A. RCMs considered in this study.

Scenario	Ensemble	RCM - Modelling center (Lake Model)	Driving GCM
RCP4.5	CORDEX-NA	CanRCM4 – CCCma (-)	CanESM2#1
		RCA4 - SMHI (FLake)	CanESM2#1
			EC-Earth#12
		CRCM5 - UQAM (Flake)	CanESM2#1
			MPI-ESM-LR#1
		HIRHAM5 - DMI (-)	EC-Earth#3
RCP8.5	CORDEX-NA	CanRCM4 – CCCma (-)	CanESM2#1
		HIRHAM5 - DMI (-)	EC-Earth#3
		RCA4 - SMHI (FLake)	CanESM2#1
			EC-Earth#12
	OURANOS	CRCM5 - Ouranos (FLake)	CanESM2#3
			CanESM2#3

A.2. WATER TEMPERATURE PROJECTIONS

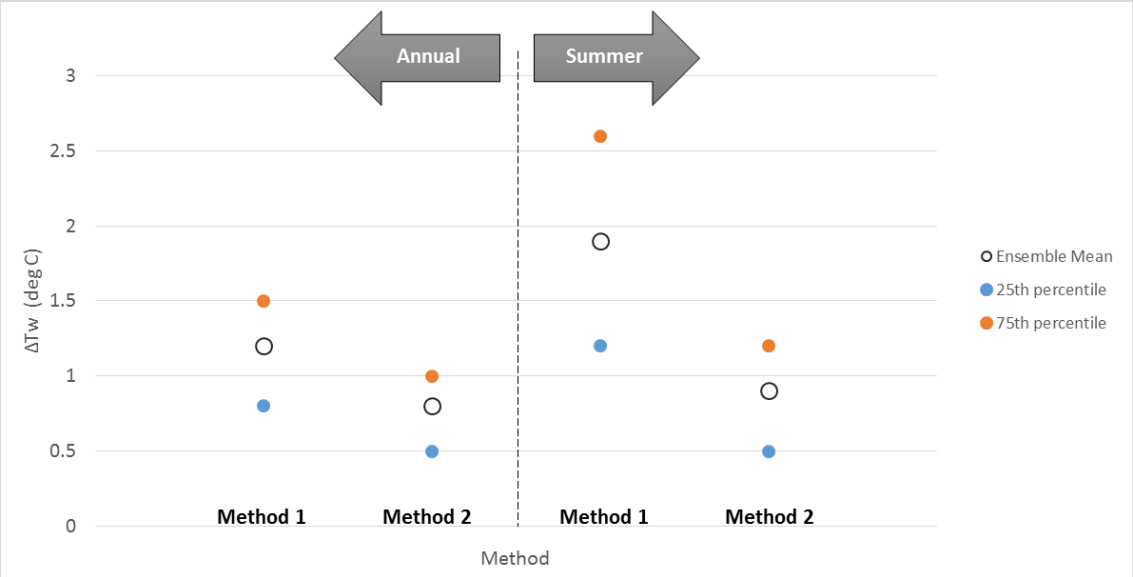

Figure A. Ensemble mean (black circles), 25th percentile (blue dots) and 75th percentile (orange dots) of changes in intake temperatures at Darlington for annual (left side) and summer (right side) time scales, obtained from the two methods used in this study. Projected changes in temperature are evaluated by subtracting long-term averages of reference values (1986-2015) from future values (2041-2070).

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Ouranos was born from the shared vision of the Government of Quebec, Hydro-Québec and Environment Canada, with financial support of Valorisation-Recherche Québec in 2001. Incorporating a network of some 450 scientists and professionals from various disciplines, the consortium focuses on two main themes: climate science and vulnerabilities, impacts and adaptation. Its mission is the acquisition and the development of knowledge on climate change and its impacts, as well as socio-economic and environmental vulnerabilities, in order to inform policy makers about climate change and advise them on how to identify, evaluate, promote and implement local and regional adaptation strategies.

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-VECC-009
Attachment 3
Page 1 of 7

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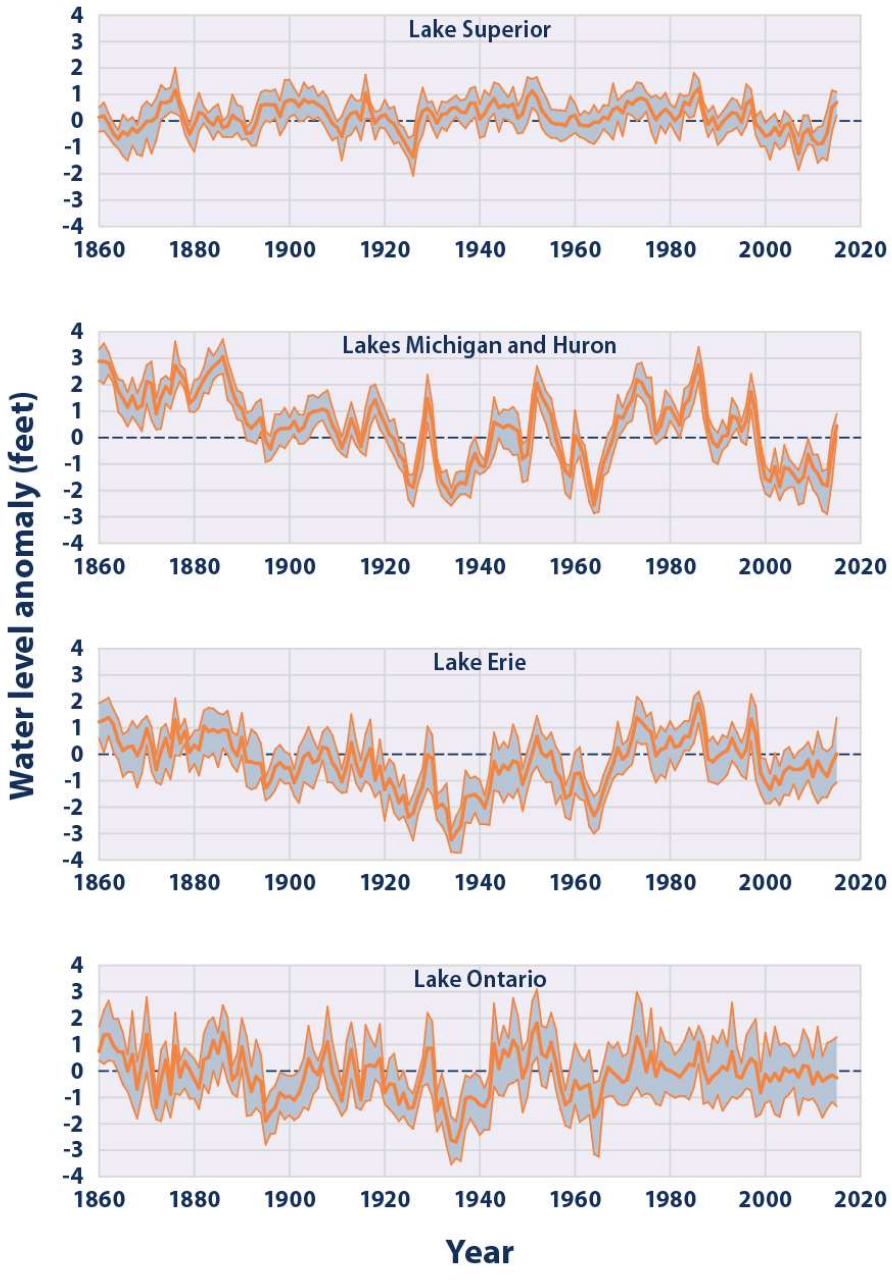
Climate Change Indicators: Great Lakes Water Levels and Temperatures

This indicator measures water levels and surface water temperatures in the Great Lakes.

Figure 1. Water Levels of the Great Lakes, 1860–2015



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EB-2020-0290
Exhibit L
C1-01-VECC-009
Attachment 3
Page 2 of 7

This figure displays how water levels in each of the Great Lakes have changed since 1860. For each year, the shaded band shows the range of monthly average water levels, and the line in the middle shows the annual average. The graph uses the 1981 to 2010 average as a baseline for depicting change. Choosing a different baseline period would not change the shape of the data over time. Lakes Michigan and Huron are shown together because they are connected at the same water level.

Data source: NOAA, 2016[6]
Web update: August 2016

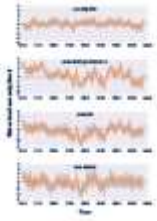

Figure 1. Water Levels of the Great Lakes, 1860–2015

Filed: 2021-04-19
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C1-01-VECC-009
Attachment 3
Page 3 of 7

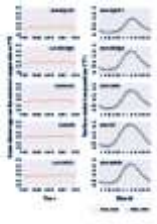

Figure 2. Surface Water Temperatures of the Great Lakes, 1995–2015

Key Points | **Background** | **About the Indicator** | **About the Data** | **Technical Documentation**

Key Points

- Water levels in the Great Lakes have fluctuated since 1860. Over the last few decades, they appear to have declined for most of the Great Lakes (see Figure 1). The most recent levels, however, are all within the range of historical variation.
- Since 1995, average surface water temperatures have increased slightly for each of the Great Lakes (see Figure 2).
- Recent increases in water temperature have mostly been driven by warming during the spring and summer months (see Figure 2). These trends could relate in part to an earlier thawing of winter ice (see the Lake Ice indicator).

Background

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-VECC-009
Attachment 3
Page 4 of 7

The Great Lakes, which are Lake Superior, Lake Michigan, Lake Huron, Lake Erie, and Lake Ontario, form the largest group of freshwater lakes on Earth. These lakes support a variety of ecosystems and play a vital role in the economy of the eight neighboring states and the Canadian province of Ontario, providing drinking water, shipping lanes, fisheries, recreational opportunities, and more.

Water level and water temperature are two important and interrelated indicators of weather and climate change in the Great Lakes. Water level (the height of the lake surface above sea level) is influenced by many factors, including precipitation, snowmelt runoff, drought, evaporation rates, and people withdrawing water for multiple uses. Water temperature is influenced by many factors, too, but most directly by air temperature.

In recent years, warmer surface water temperatures in the Great Lakes have contributed to lower water levels by increasing rates of evaporation and causing lake ice to form later than usual (see the Lake Ice indicator), which extends the season for evaporation.[1] Lower water levels in the Great Lakes forced ships to reduce their cargo tonnage by 5 to 8 percent between 1997 and 2000, which increased shipping costs. Lower water levels can also affect water supplies, the usability of infrastructure such as docks and piers, and shoreline ecosystems. These types of disruptions from low water levels are expected to continue as the climate changes.[2]

Another possible effect of warmer water, reduced ice cover, and increased evaporation is a corresponding increase in precipitation over nearby land, especially “lake effect” snow (see the Snowfall indicator).[3] Rising water temperatures are also expected to expand the ranges of and give new advantages to some invasive species such as the zebra mussel, and to encourage the growth of certain waterborne bacteria that can make people ill.[4,5]

About the Indicator

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C1-01-VECC-009
Attachment 3
Page 5 of 7

This indicator analyzes water levels and surface water temperatures in the Great Lakes. Water levels are recorded by gauges along the shore of each lake, some of which have been operated since the 1800s. Pre-1918 data came from one water level gauge per lake. Data since 1918 have come from a designated set of gauges in each lake. Figure 1 shows annual water level anomalies, or differences, in feet compared with the average water levels in each lake from 1860 to 2015. Lakes Michigan and Huron are combined because they are connected at the same water level.

Surface water temperatures are measured by satellites. Figure 2 shows annual average temperatures over the entire surface of each lake, along with the pattern of daily temperatures over the course of the year. This figure's data begin in 1995, which was the first year with complete satellite data for all five lakes.

About the Data

Indicator Notes

While climate change influences water levels, human activities such as dredging can also play a role. For example, the St. Clair river opening was enlarged in the 1910s, 1930s, and 1960s, contributing to greater outflows from Lakes Michigan and Huron.[8] Similarly, natural year-to-year variability and other factors such as human use and wastewater discharges can influence water temperatures.

Data Sources

Water level data were provided by the Canadian Hydrographic Service and the National Oceanic and Atmospheric Administration's Center for Operational Oceanographic Products and Services, and can be downloaded from: www.glerl.noaa.gov/data/dashboard/data. Surface water temperature data were provided by the National Oceanic and Atmospheric Administration's Great Lakes Environmental Research Laboratory (satellite data at: https://coastwatch.glerl.noaa.gov).

Technical Documentation

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Exhibit L
C1-01-VECC-009
Attachment 3
Page 6 of 7

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Printer-friendly PDF of all text and figures

Learn about other indicators in this section

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EB-2020-0290
Exhibit L
C1-01-VECC-009
Attachment 3
Page 7 of 7

LAST UPDATED ON NOVEMBER 2, 2020

VECC Interrogatory #10

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report

"*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*."

a) Is it Concentrics's view that implementation of OPG's proposed rate smoothing plan will lead to change in credit ratings for the utility?
b) Is it Concentrics's view that implementation of OPG's proposed rate smoothing plan increases the financial or business risk of OPG? If so please provide the quantity of that change in risk and how that is calculated.

Response

Response prepared by Concentric Energy Advisors

a) Concentric is unable to assign a specific likelihood to a credit rating action (whether a downgrade or a change in credit outlook) for OPG. As further discussed in Exhibit C1-1-1, Attachment 1, page 59, OPG's core credit ratios, which are in part impacted by rate smoothing, are expected to be under pressure during the earlier years of the upcoming rate setting period. Although Concentric understands that OPG's rate smoothing proposal in this application is based on one of the two such metrics being within threshold over the 2022-2026 period at all times, there remains an inherent risk of a credit rating action in this period.

Moody's Investors Service notes a concern with regard to OPG's rate smoothing (See Attachment 1). Specifically, Moody's states "Ontario Power Generation (OPG, A3 stable) filed a rate case on 31 December 2020 related to its nuclear generation assets and, as part of the filing, requested an increase in its existing rate smoothing deferral account (RSDA). If approved, the increase would be credit negative because a higher RSDA would result in weaker financial metrics until cost recovery begins." Moody's further explains that the RSDA increase "is credit negative because it reduces revenue and cash flow in any given year by the amount of growth in the RSDA. To offset the deferred revenue, the balance of the RSDA will be 100% debt financed at a long-term debt rate, putting more pressure on financial metrics." Moody's further states "Deferred revenues are at risk of seeing the recovery period

extended or not being recovered at all if regulations change. This negatively affects our business risk assessment of the company, as it adds a degree of political risk as future governments may find it expedient to exert downward pressure on electricity rates by further extending the recovery period or by eliminating recovery of the RSDA altogether." Finally, Moody's observes "The RSDA is unusual because investor owned utilities, to which we often compare OPG, seldom have material debt financed RSDA's. It also reflects the large size of the Darlington Refurbishment project and the associated reduction in nuclear generation which is contributing to an increase in electricity costs in the province and the use of the RSDA. Investor owned utilities seldom are required to defer revenue at the cost of debt since this reduces their debt capacity and increases the risk of unrecovered costs." (Moody's Investors Service, "Ontario Power Generation Inc., "Proposed increase in rate smoothing is credit negative," January 26, 2021)

b) Yes. As also noted by Moody's above, rate smoothing defers cash flows into the future, which increases financial risk. As discussed in Exhibit C1-1-1, Attachment 1, at 59, lower generation during the DRP, which is expected to impact the rate smoothing determinations in this proceeding and therefore OPG's future operating cash flows, provides a source of incremental financial risk to OPG. Per OPG's evidence (Ex. I1-3-2), the RSDA balance will peak at a total of $1.5 billion under OPG's proposal, with over $750 million of revenue deferred during the 2022-2026 rate term. Concentric has not further quantified the risk related to rate smoothing, but rather considered it in its assessment of the overall risk profile for the Company.

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured -Dom Curr
Outlook	Stable

Source: Moody's Investors Service

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Ontario Power Generation Inc.

Proposed increase in rate smoothing is credit negative

Ontario Power Generation (OPG, A3 stable) filed a rate case on 31 December 2020 related to its nuclear generation assets and, as part of the filing, requested an increase in its existing rate smoothing deferral account (RSDA). If approved, the increase would be credit negative because a higher RSDA would result in weaker financial metrics until cost recovery begins. In addition, RSDA balances are at risk of further delays in ultimate recovery and potentially not being recovered at all. The RSDA represents the portion of the company's revenue requirement that will not be collected in cash, leading to higher debt levels. The balance of the RSDA will be amortized and recovered in rates in future periods.

OPG's application requests an increase in the RSDA of CAD759.5 million over the 2022-2026 period covered by the rate case, with the increase peaking at around CAD800 million in 2025. This is credit negative because it reduces revenue and cash flow in any given year by the amount of growth in the RSDA. To offset the deferred revenue, the balance of the RSDA will be 100% debt financed at a long-term debt rate, putting more pressure on financial metrics. This results in more debt and a lower weighted average cost of capital compared to rate base investments made by OPG. OPG's current allowed ROE is 8.8% on its nuclear rate base with an equity capital component of 45%. The interest expense required to fund the balance in the RSDA will be deferred and recorded in the RSDA. For context, OPG's CFO pre-WC was CAD2.6 billion over the 12 months ended 30 September 2020.

Deferred revenues are at risk of seeing the recovery period extended or not being recovered at all if regulations change. This negatively affects our business risk assessment of the company, as it adds a degree of political risk as future governments may find it expedient to exert downward pressure on electricity rates by further extending the recovery period or by eliminating recovery of the RSDA altogether. For example, this happened to BC Hydro (Aaa stable) in 2019 when its owner, the Province of British Columbia (Aaa stable), recommended the complete write off of the roughly CAD1 billion in BC Hydro's rate smoothing regulatory account, which the company subsequently did.

The Province of Ontario has amended Ontario Regulation 53/05 several times over the years. This regulation mandated the creation of RSDA's and provides prescriptive rules, including the debt financing referenced above, as well as mandating the recovery of the RSDA on a straight line basis over a 10 year period. We expect OPG's RSDA recovery to begin following the completion of the CAD12.8 billion Darlington Refurbishment Project, currently forecast for late 2026.

OPG made a similar proposal in its last nuclear rate case application and ultimately deferredless than it initially requested, tempering the negative impact of the RSDA at that

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time. In the last rate case, OPG initially sought a rate smoothing account balance of CAD732 million although this declined to CAD493 million (67%) when rates were approved and established for the period 2017 to 2021. At 30 September 2020, the balance in the RSDA was CAD405 million. At its peak, if the proposed CAD759 million increase in the RSDA is approved and remains in place, the company will have about CAD1.25 billion in its rate smoothing account compared to a forecast nuclear rate base of about CAD13 billion in 2026.

The RSDA is unusual because investor owned utilities, to which we often compare OPG, seldom have material debt financed RSDA's. It also reflects the large size of the Darlington Refurbishment project and the associated reduction in nuclear generation which is contributing to an increase in electricity costs in the province and the use of the RSDA. Investor owned utilities seldom are required to defer revenue at the cost of debt since this reduces their debt capacity and increases the risk of unrecovered costs. However they are financially incentivized and may seek to repay regulated liabilities that are netted against rate base to boost shareholder returns.

OPG is unique in that is wholly owned by the Province and, unlike many other rated provincially owned electric utilities in other provinces, it does not benefit from a provincial debt guarantee or have all or almost all of its debt capital provided by its Provincial owner. In proposing an increase in the size of the RSDA, we believe OPG weighed several factors including but not limited to the financial impact of the RSDA (including leverage and cash flow impacts), rate stability and customer bill impacts and intergenerational equity which addresses whether current or future customers pay for the Darlington refurbishment. While not currently a high profile issue, electricity rates in Ontario are periodically highly political and contentious, leading successive Provincial governments to take action.

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VECC Interrogatory #11

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.44

a) Concentric presents the hypothesis that legislative protections such as O. Reg 53/05 do not provide risk reduction vis-à-vis comparisons to U.S. regulatory jurisdictions. The antidotal example given is with respect to the overturning of the *Base Load Review Act* in South Carolina. What legal analysis did Concentric carry out on that case to compare it to Canadian and Ontario laws and precedents? Please provide that analysis.

Response

Response prepared by Concentric Energy Advisors

Concentric did not perform a legal analysis of South Carolina's Base Load Review Act as compared to Ontario's O. Reg 53.05. As explained in our report, our review of these other jurisdictions was intended to demonstrate that the types of risk mitigation provided by Ontario's O. Reg. 53/05 are not particularly unique to Ontario. Other jurisdictions such as Florida, Georgia and South Carolina have implemented similar types of legislative protections in order to provide support for the construction and refurbishment of large-scale nuclear and IGCC projects. Without these protections, these types of projects would not be undertaken.

VECC Interrogatory #12

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.62/Appendix A

"….*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*…"

a) Please clarify if the S&P and Moody reports referred to are those filed by the Applicant at A2-03-01? If not, please provide the reports the authors are relying on.

Response

Response prepared by Concentric Energy Advisors

Confirmed.

VECC Interrogatory #13

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.62

A2-03-01 Attachment 10, S&P Global Ratings July 30, 2019:
"*The negative outlook reflects the potential for limited cushion in OPG's credit metrics and weak financial measures as a result of recent acquisitions. Furthermore, the negative outlook also reflects the potential for additional acquisitions during our outlook period that could further stress credit metrics and the execution and integration risks associated with the transaction. During our two-year outlook period, we expect FFO to debt of about 13% from 2019-2020*."

A2-03-01 Attachment 3, DBRS April 16, 2019:
"*OPG additionally acquired Eagle Creek in November 2018 for USD 298 million. DBRS views the business risk profile of Eagle Creek to be weaker than OPG as it is not regulated and not all of its facilities operate under long-term contracts, resulting in higher volume and price risk.* "

a) OPG has embarked on a strategy of acquiring (or increasing its share in) a significant number of merchant generation assets including Eagle Creek, Cube Hydro. As shown in the above excerpts some market analyst believes these acquisitions could impact OPG's risk profile. How has the impact of OPG new strategy been factored into Concentrics's analysis and projection of OPG's regulated assets risk profile? Specifically, what adjustments have the author's made to account for credit reports which consider the Company as a whole?

Response

Response prepared by Concentric Energy Advisors

Consistent with the OEB's practice for establishing the equity thickness for OPG, Concentric's analysis and recommendation are focused on OPG's regulated operations, and thus the impact of OPG's unregulated facilities (whether previously owned or recently acquired) is not factored into our assessment.

As a general matter, Concentric notes that while S&P has identified OPG's recent acquisitions as being somewhat credit negative for OPG, S&P also finds that its

"business risk assessment continues to reflect OPG's stable regulated electricity generation operation under a generally supportive regulatory framework and effective management of regulatory risk. We expect regulated operation will continue to provide about 70% of OPG's cash flow. Although the transaction will increase the utility's unregulated power exposure, contributing about 30% of overall cash flow, this is offset by long-term contracts with more than five years remaining, favorable rate constructs, investment-grade counterparties, and minimal exposure to electricity commodity risks." In addition, following the completion of OPG's acquisition of gas assets in 2020, S&P revised its outlook on OPG from negative to stable, which S&P attributed in part to its "expectations that the company will pause on its acquisition strategy." (S&P Global Ratings, "Ontario Power Generation Inc. Outlook Revised To Stable From Negative; 'BBB+' Rating Affirmed," July 17, 2020). Also see L-C1-01-SEC-31.

VECC Interrogatory #14

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.63-64

"*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*."

Figures 14 and 15 which the above reference refer to show numbers ranging between 45.7% to 55.9%. Given that range how to the author's then conclude an equity ratio of "*no less than 50%*." Is warranted?

Response

Response prepared by Concentric Energy Advisors

Concentric's recommended equity thickness and the basis for that recommendation are discussed at length in Exhibit C1-1-1, Attachment 1. In particular, please see page 10 of Concentric's report, which summarizes our assessment of OPG's risk profile relative to proxy group companies, and what impact that risk profile (when considered along with prior OEB findings) has on our assessment of an appropriate equity thickness for OPG.

VECC Interrogatory #15

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.67

a) Please provide the proportion of total OPG electricity revenue generated by only regulated assets in each of 2017 through 2020?
b) What is the forecast proportion of total revenues that will be generated from regulated assets in each of the years 2021 through 2026?

Response

a) The total OPG electricity revenue generated by the regulated assets as a proportion of OPG's total electricity revenue is presented in the chart below.

Year	Electricity revenue – regulated assets (%)
2017	88
2018	89
2019	89
2020	84

b) The forecast proportion of total OPG revenue that will be generated from the regulated assets as a proportion of OPG's total revenue is presented in the chart below.

Year	Total revenue - regulated assets (%)
2021	[redacted]
2022	
2023	
2024	
2025	
2026	

VECC Interrogatory #16

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, Fig.16, p.70

a) How many companies own or operate nuclear generation in North America and are not included in the list at Figure 16?

Response

Response prepared by Concentric Energy Advisors

According to data from S&P Global Market Intelligence, four regulated electric utilities own regulated nuclear generation and are not included in Figure 16 of the Concentric Report. The bullets below list those utilities, and summarize the reason each company was not included in Concentric's proxy group:

- Dominion Resources Inc – excluded from the Concentric proxy group for deriving less than 80 percent of its regulated revenue and income from electric operations.
- DTE Energy Company – excluded from the Concentric proxy group for deriving less than 60 percent of its revenue from regulated operations, and for deriving less than 80 percent of its regulated revenue from electric operations.
- Exelon Corporation – excluded from the Concentric proxy group for deriving less than 60 percent of its revenue from regulated operations. Note, Exelon Corporation is included in the Moody's Proxy Group

PG&E Corporation – excluded from the Concentric proxy group for having a credit rating that is below investment grade.

VECC Interrogatory #17

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report, p.79

a) Please provide the Georgia PSC Order Docket 42516 (footnote 130).

Response

See Attachment 1.

Docket No. 42516

In Re: Georgia Power Company's 2019 Rate Case

ORDER ADOPTING
SETTLEMENT AGREEMENT AS MODIFIED

Record Submitted: November 27, 2019 Decided: December 17, 2019

APPEARANCES

On behalf of Georgia Public Service Commission Public Interest Advocacy Staff:

JEFFREY STAIR, Esq., DANIEL WALSH, Esq., and PRESTON THOMAS, Esq.

On behalf of Georgia Power Company:

KEVIN C. GREENE, Esq., BRANDON MARZO, Esq., and STEVE HEWITSON, Esq.

On behalf of the City of Atlanta:

NINA R. HICKSON, Esq., and NEWTON GALLOWAY, Esq.

On behalf of The Commercial Group:

ALAN R. JENKINS, Esq.

On behalf of Georgia Association of Manufacturers:

CHARLES B. JONES, III, Esq.

On behalf of Georgia Industrial Group:

RANDALL D. QUINTRELL, Esq.

On behalf of Georgia Interfaith Power & Light, Southface Energy Institute, and Vote Solar:

KURT EBERSBACH, Esq., and JILLIAN KYSOR, Esq.

On behalf of Georgia Solar Energy Industries Association, Inc.:

NEWTON M. GALLOWAY, Esq., and TERRI M. LYNDALL, Esq.

On behalf of Georgia Restaurant Association:

PERRY J. McGUIRE, Esq., and VICKIE C. RUSEK, Esq.

On behalf of Georgia Watch:

LIZ COYLE

On behalf of The Kroger Company:

KURT J. BOEHM, Esq., and JODY KYLER COHN, Esq.

On behalf of Metropolitan Atlanta Rapid Transit Authority:

ROBERT B. BAKER, JR., Esq.

On behalf of Resource Supply Management:

JIM CLARKSON

On behalf of Sierra Club:

ROBERT JACKSON, Esq., and ZACHERY M. FABISH, Esq.

On behalf of U.S. Department of Defense and other affected Federal Executive Agencies:

EMILY W. MEDLYN, Esq.

BY THE COMMISSION:

I. GEORGIA POWER COMPANY'S 2019 RATE CASE STATEMENT OF PROCEEDINGS

Pursuant to the Rate Plan approved by the Georgia Public Service Commission ("Commission") in the December 17, 2013 Order Adopting Settlement Agreement in Docket No. 36989-U, Georgia Power Company's 2013 Rate Case, the Commission ordered Georgia Power Company ("GPC" or "Company") to file by July 1, 2016, a general rate case for dealing with any changes in revenue requirements. Subsequent to that decision, the Commission established in its April 14, 2016 decision on the Joint Request of Atlanta Gas Light Company, AGL Resources Inc., and The Southern Company for a Finding that Southern Company's Merger with AGL Resources Complies With Applicable Law And SouthStar Energy Services LLC d/b/a Georgia Natural Gas; Application for a Natural Gas Marketer Certificate of Authority filed respectively in Dockets 39971 and 9574 that the current 2013 Georgia Power accounting order would continue in effect until December 31, 2019 and Georgia Power would file its next retail rate case, or request for an accounting order, on July 1, 2019.

On May 21, 2019, in accordance O.C.G.A. § 50-13-13, the Commission entered a Procedural and Scheduling Order ("PSO") to govern the hearings. On June 28, 2019, pursuant to the PSO, Georgia Power Company filed its 2019 Rate Case. On September 24, 2019, Georgia Power filed an errata to reflect the revenue requirement impacts from various items included in the amended Stipulation approved by the Commission in the Company's 2019 Integrated Resource Plan ("IRP") and DSM Certification proceedings in Docket Nos. 42310 and 42311 ("Errata").

Georgia Power's 2019 Rate Case filing, as amended by the Errata, requested approval to continue the three-year alternate rate plan ("ARP") structure and requested rate increases of $560 million, $144 million and $233 million to be effective January 1, 2020, 2021 and 2022, respectively. These proposed increases included a one-time levelized adjustment for traditional base rates and Environmental Compliance Cost Recovery ("ECCR") tariffs and annual increases to recover compliance costs associated with ash pond closure as well as the Demand Side Management ("DSM") and Municipal Franchise Fee ("MFF") tariffs. Hearings on Georgia Power's direct case in support of its filing were held September 30, 2019 through October 2, 2019.

In addition to the Commission's Public Interest Advocacy Staff ("PIA Staff"), which has a statutory right to participate in this proceeding, interventions were filed by a number of interested parties. These interested parties included the City of Atlanta; the Commercial Group; Concerned Ratepayers of Georgia; the U.S. Department of Defense (on behalf of all Other Federal Executive Agencies) ("DOD/FEA"); Georgia Association of Manufacturers ("GAM"); Georgia Industrial Group ("GIG"); Georgia Interfaith Power & Light, Inc. ("GIPL"), Southface Energy Institute, Inc. ("Southface"), and Vote Solar, Inc.; the Georgia Solar Energy Association, Inc. ("GSEA") and Georgia Solar Energy Industries Association ("GSEIA"); Georgia Restaurant Association ("GRA"); Georgia Watch; The Kroger Company ("Kroger"); Metropolitan Atlanta Rapid Transit Authority ("MARTA"); Resource Supply Management ("RSM"); and the Sierra Club. Thereafter, on October 17, 2019, PIA Staff and Intervenors filed testimony and exhibits presenting their

respective direct cases. With the exception of Concerned Ratepayers of Georgia, GSEIA/GSEA, and Georgia Watch, all other parties to this case filed testimony in this proceeding. Hearings on PIA Staff and Intervenors' direct cases were held November 4, 2019 through November 6, 2019.

The Company filed its rebuttal testimony on November 15, 2019 in response to the positions advocated by PIA Staff and various Intervenors. The Company presented its rebuttal case on November 25, 2019, at which time the hearings in this matter were concluded. On December 4, 2019, parties in this matter filed proposed orders and briefs.

At each phase of the hearings of evidence in this case the Commission also heard from numerous public witnesses who expressed their views on the Company's application, either individually or on behalf of specific groups.

II. COMMISSION ACTION

Following its rebuttal testimony, the Company filed a proposed Settlement Agreement ("Proposed Agreement") intended to resolve the issues in the case except for the return on equity ("ROE") to be assumed in setting the Company's retail rates and the appropriate level of equity in the Company's capital structure. Other than those two issues, the Proposed Agreement provided that Company's filing would be accepted with the modifications contained in the Proposed Agreement. The Proposed Agreement was executed on behalf of the Company and several Intervenors. The following parties executed the Proposed Agreement: the Commercial Group, GIG, GAM, the City of Atlanta, MARTA, and Kroger.

Under the Proposed Agreement, rates would go into effect January 1, 2020 using a three-year ARP with an earnings band of 9.50% to 12.00%. Rates under the ARP would be set as described in the Settlement Agreement using an ROE and capital structure to be set by the Commission. The Proposed Agreement further provided for the continuation of the ECCR Tariff which would collect certain environmental costs that will be incurred by the Company including compliance with Coal Combustion Residual Asset Retirement Obligations ("CCR ARO"). The Proposed Agreement further provided for an increase in the MFF tariff as well as an increase in the DSM tariffs.

The Proposed Agreement also provided that the traditional base tariffs would be adjusted in 2021 and 2022 to recover the revenue requirements for traditional base rates, the ECCR tariff, the DSM tariffs, and the MFF tariff. The Proposed Agreement also provided for continuation of the Interim Cost Recovery ("ICR") mechanism approved in the 2010 Rate Case in Docket No. 31958 throughout the term of this ARP utilizing the earnings band in Paragraph 6 of the Proposed Agreement. For Annual Surveillance Reporting ("ASR") purposes, beginning January 1, 2020, the earnings band would be set at 9.5% to 12.0% ROE and the Company would report earnings based on the actual historic cost of debt and approved capital structure. The Company would not file a general rate case unless its calendar year retail earnings are projected to be less than 9.5% ROE.

At its regular Administrative Session held on December 17, 2019, the Commission voted to adopt a Commissioner Motion ("Motion") to accept the Proposed Agreement with certain modifications set forth in the Motion, set the ROE at 10.50%, and set the capital structure at 56% equity and 44% debt (referred to herein as the "Settlement Agreement as Modified"). At its regular Administrative Session held on February 4, 2020, the Commission clarified its decision to explain that the 32 MW threshold for installed rooftop solar capacity relating to Behind the Meter netting was for newly installed capacity and did not include existing installed rooftop solar capacity.

FINDINGS OF FACT

1.

The Commission finds that the resolution of the matters raised in this docket, as provided in the Settlement Agreement as Modified, is appropriate and in the best interest of the State of Georgia. It is supported by testimony and other evidence in the record and will result in just and reasonable rates. In discussing the individual components of the Settlement Agreement as Modified, the Commission remains mindful that the Proposed Agreement reflected a compromise among a number of parties with disparate interest, and that the Settlement Agreement as Modified must be considered as a whole. It is plain from reviewing the resolution that no party to the proceeding, including every party that signed on to the Proposed Agreement, prevailed on every issue. However, the Settlement Agreement as Modified offers a fair resolution to the full range of issues presented in this docket.

2.

As set forth in the Motion, the Commission finds that rates shall be set using a 10.50% ROE, which appropriately balances the interests of the Company and its customers, and which the Commission finds to be just and reasonable. The difference between the respective ROE recommendations of Georgia Power and those of PIA Staff and other Intervenors represented the largest dollar amount of any single issue in the case. Georgia Power recommended a ROE of 10.9%.

PIA Staff recommended a 9.2% ROE with a range of 9 - 9.4%. PIA Staff argued that authorization of a ROE of 9.2 percent would be consistent with the principles set forth in Bluefield Waterworks and Improvement Co. v. Serv. Comm'n, 262 U.S. 679 (1923), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). PIA Staff stated that their proposed ROE would reasonably balance just and reasonable rates to customers, the financial integrity of the Company and fair compensation to investors. PIA Staff further stated that the Company's witness' comparable earnings analysis should be rejected because the analysis does not measure the market required return appropriate for the investment risk of Georgia Power. PIA Staff pointed to the Federal Energy Regulatory Commission's ("FERC") decision in Docket EL14-12-003, where FERC concluded that relying on the comparable earnings model would not satisfy the requirements of the Fed. Power Comm'n v. Hope Natural Gas Co. decision. (Tr. 2575).

DOD/FEA recommended a ROE of 9.1%. The witness for DOD/FEA also stated that the financial risk adjustment is not needed because the difference between Georgia Power's book-value and capital structure and the proxy group's market-value capital structure is already captured in the various market-based ROE methodologies.

The Commission finds and concludes that a ROE of 10.5% will allow the Company continued access to the capital markets at competitive rates and will allow the Company to construct infrastructure necessary to serve customers and comply with environmental regulations. Accordingly, the Commission finds that the appropriate ROE for setting rates is 10.50%.

3.

Additionally, the Commission approves a capital structure of 56% equity and 44% long term debt for the test period. Georgia Power proposed that a capital structure containing approximately 44% debt and 56% common equity be used for ratemaking purposes in this proceeding. The Company maintained that the proposed ROE and 56% equity ratio will ensure that Georgia Power has access to capital whenever necessary, provide the opportunity to earn a fair return for its investors and will do so at rates favorable to customers.

PIA Staff proposed a capital structure for the Company composed of 49% long-term debt and 51% common equity. (Tr. 1510). PIA Staff stated that the capital structure proposed by its witness will comfortably support the Company's current investment grade bond rating, but do so at a much lower cost to ratepayers than the Company's proposed ratemaking capital structure. PIA Staff also argued that its witness's proposed ratemaking capital structure is consistent with the industry mix of debt and equity that is supportive of the Company's current investment grade bond rating. (Tr. 1508).

Based 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.

4.

PIA Staff's witness recommended a 4.07% cost of debt as shown in Staff Exhibit_(RS/RT-2), Schedule D of Smith-Trokey Testimony. PIA Staff's witness adjusted GPC's bond issues made in August 2019 to the actual interest rates GPC received and adjusted the bond issues interest rates to 3.65% for the period of March 2020 through October 2022, (Gorman Direct Testimony, Table 7).

The Company stated in its brief that PIA Staff's witness' adjustments were neither necessary or appropriate adjustments. The Company argued first, PIA Staff's recommended adjustment to the cost of debt revises only one component of the Company's filing impacted by interest rates and creates inconsistencies with the interest rate assumptions throughout the remainder of the Company's filing. (Tr. 2629.) And second, PIA Staff's adjustment of projected cost of debt to 3.65% for the projected issuances beyond March 2020 is inappropriate for forecasting the Company's future cost of debt. (GPC Post Hearing Brief p. 17)

The Commission was not sufficiently swayed by PIA Staff's position, therefore, PIA Staff's recommendation is denied.

5.

The Proposed Agreement provides that, effective January 1, 2020, the Company shall (1) not increase its traditional base rate tariff in 2020, any increases in base rates in 2021 and 2022 shall not be levelized but adjusted year by year, (2) collect an additional $12 million through the DSM tariffs, and as adjusted during the term of this ARP based on the DSM True up process agreed to by the Company and Commission Staff with projected increases of $1 million effective January 1, 2021, and $1 million effective January 1, 2022 and (3) collect an additional $12 million effective January 1, 2020, $5 million effective January 1, 2021, and $9 million effective January 1, 2022 through the MFF tariff, which dollar amount will change as total revenues change as allowed by this ARP, as well as with any future Fuel Cost Recovery ("FCR") changes and future Nuclear Construction Cost Recovery ("NCCR") changes. (Proposed Agreement Provisions 1, 3 and 4).

The Commission finds these tariff changes to be reasonable; therefore, the changes are approved as provided for in the Proposed Agreement.

6.

The Proposed Agreement provides that the revenue requirement amount related to coal ash pond AROs shall be collected through the ECCR tariff effective January 1, 2020. ECCR shall include the cost for compliance with CCR ARO. The collection of CCR AROs through ECCR will be in addition to compliance costs already included in the ECCR tariff. For purposes of settlement, the forecasted contingency for CCR AROs and traditional ECCR has been removed from the annual expenditure projections. For rate setting purposes the full weighted average cost of capital will be applied to the under recovered balance of CCR AROs. Effective January 1, 2020, it was estimated that the ECCR tariff would be adjusted to collect an additional $324 million, an estimated $115 million effective January 1, 2021, and $180 million effective January 1, 2022. These estimates will be adjusted in setting actual 2020 ECCR tariff rate and in the Company's compliance filings to incorporate the capital structure and rate setting return on equity approved by the Commission. The projection of CCR ARO cost will be updated in 2020 and 2021 through compliance filings to set the actual ECCR tariff rates for 2021 and 2022. (Proposed Agreement Provisions 2 & 5).

PIA Staff's recommended CCR ARO revenue requirement deficiency for 2020 is $104.6 million, which is $53.5 million less than the Company's proposed amount. (Tr. 1212). PIA Staff did not object to the one-third amortization per year approach for cost recovery proposed by the Company, but recommended three modifications to the Company's proposal. First, PIA Staff recommended that the Commission not pre-approve a level of cost recovery for 2021 and 2022 because the actual costs may vary from the Company's estimates. Instead, PIA Staff recommended that the Company's annual compliance filing as approved in the 2019 IRP. Second, PIA Staff

recommended that the Commission not approve contingency dollars included by the Company in the estimates that the Company used to derive its requested CCR ARO compliance revenue requirements for the test year, and for plan years 2020 through 2022. They argued removal of the contingency dollars is appropriate here because the Company's estimates included a substantial contingency, the Company will have the opportunity to mitigate and offset costs, and some portions of the Company's contingency estimates have a low probability of being incurred. (Tr. 1207-1208). Finally, PIA Staff recommended that the Company receive a carrying cost allowance based on the cost of long-term debt with no ROE component, rather than a full rate base return (including an equity return and income tax gross-up) on the CCR ARO amounts while they are being recovered.

DOD/FEA recommended that given the substantial size and uncertainty of the amount of CCR costs to be recovered, the Commission should order that Georgia Power recovers these costs through an exact cost recovery rider designed as a percent of base revenue structured in a similar fashion as Georgia Power's current base-rate recovery riders tariff, e.g. Nuclear Construction Cost Recovery tariff. DOD/FEA further recommended that if the Commission does not think transparency is necessary in relation to billing of CCR ARO costs, hence that cost recovery through a new rider is unwarranted, the Commission should order CCR ARO costs to be recovered through the ECCR tariff.

Sierra Club recommended that the Commission deny the Company's request to recover $525 million from its ratepayers for its CCR costs stating that Georgia Power failed to demonstrate that its costs are just, reasonable and prudent. Sierra Club stated that the Company failed to provide a cost accounting, cost breakdown or list of line item expenses breaking down how or when the $525 million will be spent. Sierra Club also asserted that the CCR costs should be disallowed as those future costs are uncertain. Since the Georgia EPD has yet to approve Georgia Power's CCR closure plans, Sierra Club argued that the Company is attempting to recover, from ratepayers, costs that are indefinite, uncertain and could change.

This Commission has carefully considered the evidence and testimony presented on these issues and finds that it is just and reasonable for Georgia Power to recover CCR ARO compliance costs as provided for in the Proposed Agreement.

7.

For ASR purposes, beginning January 1, 2020, the earnings band shall be set at 9.5% to 12.0% ROE and the Company shall report earnings based on the actual historic cost of debt and approved capital structure. The Company shall not file a general rate case unless its calendar year retail earnings are projected to be less than 9.5% ROE. (Agreement Provision 6).

PIA Staff has recommended an earnings band from 9.20 to 10.50% and recommended that earnings above the band be applied to deferred costs instead of being split between customers and the Company. (Tr. 1316.)

DOD/FEA's witness recommended narrowing the ROE earnings band to +/- 50 basis points around the authorized ROE based on the assumption that it would reduce the risk to the Company. (Tr. 1015.) This assumption, however, fails to recognize that by reducing the risk to the Company it would necessarily increase the risk to customers. (Tr. 2636.) Increasing the risk to customers alters the fundamental nature of the ARPs that have been in place for the last 25 years. (*Id*.) Georgia Power has proposed an earnings band approximately +/-100 basis points around the proposed ROE, consistent with the structure of the earnings bands previously approved by the Commission for the last several decades.

The Commission finds that the earnings band for ASR purposes and the Company's agreement not to file a general rate case unless its calendar year retail earnings are projected to be less than 9.5% are reasonable and is hereby approved.

8.

The Proposed Agreement provides that subsequent to finalization of PIA Staff's review of the respective ASR, any retail earnings above 12.0% ROE shall be shared, with forty percent (40%) being applied to regulatory assets in the following priority: Accumulated CCR ARO, Retired Generating Plant, Obsolete Inventory, Environmental Remediation, and Storm Damage, forty percent (40%) being directly refunded to customers, allocated on a percentage basis to all customer groups including the base revenue contribution of Real Time Pricing ("RTP") incremental usage, and the remaining twenty percent (20%) retained by the Company. The Commission finds that it is fair and reasonable that in the event the Company is earning above the top end of the earnings band, sharing occurs in accordance with the Settlement Agreement. (Proposed Agreement Provision 7).

The Commission finds this provision of the Proposed Agreement to be reasonable and is hereby approved.

9.

The Proposed Agreement provides that the Company shall make its ASR filings for this ARP by March 15th of the following year. The Commission will consider the ASR filing and determine any direct refunds and reduction of regulatory assets by July 31st of that year. (Proposed Agreement Provision 8).

The Commission finds this provision of the Proposed Agreement to be reasonable and is hereby approved.

10.

For purposes of the 2021 and 2022 rate adjustments, the Company shall make compliance filings of the updated tariffs at least ninety (90) days prior to the effective date of the tariffs. The Company's compliance filings will include the following updates including updated estimates to

incorporate the capital structure and rate setting return on equity approved by the Commission on December 17, 2019:

a) Effective January 1, 2021, (i) the traditional base tariffs shall be adjusted to collect an additional estimated $93 million. This estimate shall be adjusted in the Company's compliance filing to incorporate the capital structure and rate setting return on equity approved by the Commission; (ii) the ECCR tariff shall be increased based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual report for calendar year 2020; (iii) the DSM tariff shall be increased to reflect the additional approved DSM costs for calendar year 2021 as approved in Docket No. 42311 and as adjusted based on the DSM True up process agreed to by the Company and PIA Staff; and (iv) the MFF tariff shall be adjusted to collect the municipal franchise fee cost incurred by the Company. The 2021 increase to traditional base rate tariffs, ECCR tariff, DSM tariff will use the most current kWh sales forecast for the applicable year to set the rates.

b) Effective January 1, 2022, (i) the traditional base tariffs shall be adjusted to collect an additional estimated $197 million. This estimate shall be adjusted in the Company's compliance filing to incorporate the capital structure and rate setting return on equity approved by the Commission; (ii) the ECCR tariff shall be increased based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual report for calendar year 2021; (iii) the DSM tariff shall be increased to reflect the additional approved DSM costs for calendar year 2022 as approved in Docket No. 42311 and as adjusted based on the DSM True up process agreed to by the Company and PIA Staff; and (iv) the MFF tariff shall be adjusted to collect the municipal franchise fee cost incurred by the Company. The 2022 increase to traditional base rate tariffs, ECCR tariff, DSM tariff will use the most current kWh sales forecast for the applicable year to set the rates.

The Commission finds that the Proposed Agreement is reasonable as it pertains to the above rate adjustments and compliance filing requirements.

11.

The Proposed Agreement provides that for book accounting and ASR purposes, the schedule for the Nuclear Decommissioning Trust – Tax Funding (reference the "Proposed Supplemental Order – Nuclear Decommissioning Costs" attached to the Proposed Agreement) are approved. (Proposed Agreement Provision 10).

The Commission finds and concludes that the proposed Supplemental Order – Nuclear Decommissioning Costs is reasonable and approved.

12.

Regarding earnings that the Company has reported above the earnings band in 2018 to the Commission through the ASR process in Docket No. 36989, the Proposed Agreement provides that fifty percent (50%) of the customer share (approximately $51 million) of earnings above the band in 2018 shall be utilized to reduce the December 31, 2019, storm damage regulatory asset. Regulatory assets are to be written down in the following priority: Obsolete Inventory, Environmental Remediation, Accumulated CCR ARO, Retired Generating Plant, and Storm Damage. The remaining fifty percent (50%) of the customer share shall be refunded to customers in 2020 with a special line-item on the bill. (Proposed Agreement Provision 11).

In the Proposed Agreement, the Company anticipates earnings in excess of the earnings band in 2019. The Company shall forego its share of the 2019 earnings over the top of the earnings band. Fifty percent (50%) of all the earnings over the 2019 band shall be refunded to customers with a special line item on the bill, and fifty percent (50%) shall be used for the early retirement of regulatory assets including $49 million spent to investigate the Stewart County site and other regulatory assets in the following priority: Accumulated CCR ARO, Retired Generating Plant, Obsolete Inventory, Environmental Remediation, and Storm Damage. (Proposed Agreement Provision 12).

The Commission finds that the treatment as set out in the Proposed Agreement for the earnings above the band in 2018 and 2019 are reasonable and approved.

13.

The Proposed Agreement also provides that the Company shall accelerate amortization of an estimated $88 million in regulatory assets in 2020 in the following priority: Accumulated CCR ARO, Retired Generating Plant, Storm Damage, Obsolete Inventory, and Environmental Remediation. The actual amount accelerated may be different than estimated in this paragraph depending upon the capital structure and rate setting return on equity approved by the Commission. The estimated $88 million shall be adjusted to reflect the updated projected revenue sufficiency by incorporating the capital structure and rate setting return on equity approved by the Commission and will be reflected in the Company's compliance filing. (Proposed Agreement Provision 13).

Additionally, the Proposed Agreement provides that, in the event the Company determines that an asset is impaired or the Commission approves the retirement of a retail generation asset as a result of any environmental regulation or legislation, the Company may request that costs associated with such impairment or retirement be deferred as a regulatory asset. (Proposed Agreement Provision 14).

The Commission finds that Proposed Agreement provisions 13 and 14 are reasonable and approved.

14.

The ICR mechanism approved in the 2010 Rate Case in Docket No. 31958 is continued throughout the term of this ARP utilizing the earnings band of 9.5% to 12.0% as set for the ASR. (Agreement Provision 15). Under the ICR mechanism, if at any time during the term of the ARP, the Company projects that its retail earnings will be lower than 9.50% retail ROE for any calendar year, based on the most recent budget, including the latest projections regarding rate base, revenues, expenses, changes in projected debt and preferred security costs, it may petition the Commission for the implementation of an ICR tariff which will be used to adjust the Company's earnings back to 9.50% ROE. Any ICR tariff approved by the Commission shall expire at the earlier of the date upon which the next general rate case takes effect or the end of the calendar year in which the ICR tariff becomes effective. Continuation of the ICR mechanism also maintains certain procedural guidelines regarding the filing of any request for implementation of an ICR tariff, and further maintains that in lieu of requesting implementation of an ICR tariff, or if the Commission chooses not to implement the ICR, the Company may file a full rate case. Georgia Power must file its request to implement the ICR tariff no less than 90 days prior to its proposed effective date.

As with prior Commission-approved plans, PIA Staff's proposed ARP would also permit the Company to petition the Commission to increase rates up to the lower end of the band if its projected earnings would fall below the lower band over the upcoming calendar year. (Tr. 1301). As discussed above, however, PIA Staff's recommended earnings band was 9.2% ROE to 10.5%. (Tr. 1305).

The Commission finds that the portion of the Proposed Agreement allowing for continuation of the ICR mechanism during the term of the rate plan is just and reasonable.

15.

The Proposed Agreement provides that, with the exception of easements and right of ways, Generation and Transmission property in Plant Held for Future Use ("PHFFU") that has been held in PHFFU account for 15 consecutive years shall undergo review during the first IRP proceeding following the 15th year that such property has been held in PHFFU. Distribution property in PHFFU that has been held in PHFFU account for 15 consecutive years shall undergo review during the first base rate proceeding following the 15th year that such property has been held in PHFFU. In the respective proceeding, the Company will be required to present the specific plan for the property(s) that has exceeded 15 consecutive years in PHFFU. The Commission will decide the matter in that proceeding. (Agreement Provision 16).

PIA Staff cited three major concerns for the property held in PHFFU. First, there is a substantial dollar amount of PHFFU in rate base. Second, the overwhelming majority of the land in PHFFU is not expected to be used and useful in the provision of electric service for a considerable amount of time. Third, the expected use dates are routinely being pushed further into the future. Due to those concerns, PIA Staff proposed that, prospectively starting with this rate

case, the Commission order that if PHFFU has been held for more than 15 years and has not yet been placed into service, that such PHFFU be removed from rate base until it is placed into service.

Additionally, PIA Staff recommended that gains and losses on the sale of land held in PHFFU be shared with ratepayers based on the amount of time the land was held in PHFFU compared to the total time the land was held by the Company up to a maximum sharing of 80% for customers. (Tr. 1255.)

The Commission finds that the method for reviewing PHFFU as laid out in the Proposed Agreement is reasonable and makes no changes as it relates to the Commission's treatment of gains and losses on sales of property.

16.

The Proposed Agreement provides that beginning in 2021, with the adjustment to traditional base rate tariffs, the rate increase shall be allocated by rate group, except as otherwise provided in Proposed Agreement, with adjustments for balancing. Rates in Medium Business and Large Business rate groups will receive 85% of the overall base rate increase with the resulting revenue deficiency being spread to the other rate groups excluding the Small Business, Lighting and Marginal rate groups which will receive the overall base rate increase. (Agreement Provision 17).

The Commission finds this provision of the Proposed Agreement to be just and reasonable, and is hereby approved.

17.

The Proposed Agreement provides that the Basic Service Charge ("BSC") for all tariffs in the Domestic Group shall increase by $2 in 2021 and another $2 in 2022. Further, effective January 1, 2021, the BSC for all tariffs in the Medium Business, Large Business and Marginally priced tariff groups shall be increased to 100% of the levels shown in the Company's Exhibit LTL-1 column labeled "Period 1 Cost of Service Study Customer Related Costs" rounded to the nearest dollar. The remainder of tariff groups, with the exception of the Domestic Group addressed in Paragraph 18 of the Proposed Agreement, shall have its BSC adjusted as proposed by the Company in Exhibit LTL-1 column labeled "2021 Estimated Alternative Rate Plan Basic Service Charge" starting in 2021. The kWh and/or demand charges in each rate shall be correspondingly adjusted to collect the revenue requirement. (Agreement Provisions 18 & 19).

PIA Staff proposed an increase in the monthly BSC from $10.00 to $12.00 to become effective January 1, 2021. (PIA Staff Post Hearing Brief p. 46). However, PIA Staff did not recommend any further increase. PIA Staff contended that any large increase should not be accelerated so that it is all assessed in the first year, but instead to adhere to the concept of gradualism and slowly increase the amount of the BSC. Regardless of what was decided as the appropriate amount for the BSC, PIA Staff asserted that multi-year phase-in should reflect an even dollar increase over a period of up to 3 years, as opposed to the accelerated schedule proposed by the Company. (*Id.*)

Sierra Club argued that the BSC should remain at $10. They stated that a change from $10 to $17.95 is not necessary or in the public interest as it will result in rate shock, hurt low-usage and low-income customers disproportionally, reduce customer control over their bill, and reduce incentives for energy efficiency, conservation and distributed generation. (Sierra Club Post Hearing Brief p. 3-6).

GIPL/Southface/Vote Solar also maintained this position. The parties agree that a higher fixed charge will more significantly impact customers that use less electricity. (See Tr. 707, 1670, 2049). It will result in disproportionate bill increases for low-income customers. (Tr. 2049-50). Low-income customers tend to use less energy on average than the average residential customer, as data provided by Georgia Power shows. (Tr. 2050). GIPL/Southface/Vote Solar state that Georgia Power's current residential BSC is equal to the national median fixed charge among IOUs and just below the national average. (Tr. 2039, 2079-80; GIPL/Southface/Vote Solar Resp. to Hearing Req.). GIPL/Southface/Vote Solar argued that Georgia Power is requesting an almost $8/month increase in the residential BSC compared to the median fixed charge increase among IOUs during the last five years at $0.50/month and the average increase is just below $2/month. (Tr. 2040, GIPL/Southface/Vote Solar Post Hearing Brief p.7). They state that this increase will result in rate shock.

The Commission concludes that the $2 increase in the BSC for 2021 and again in 2022 should alleviate some of the concerns voiced by PIA Staff and Intervenors because these increases are more directly tied in with the concept of gradualism. The Commission finds that the $2 increase to the BSC in 2021 and 2022 in the Proposed Agreement are reasonable and adequately weigh the interests of both the Company and its ratepayers.

18.

The Proposed Agreement states that the Company will maintain the Residential Service tariff, the R tariff, as a rate option available to all residential customers for the term of the ARP. The Proposed Agreement also provides that the Company and Commission Staff shall collaborate in 2020 to increase marketing of the TOU-RD rate. Beginning January 1, 2021, the Company shall utilize the TOU-RD rate as the default rate for newly constructed residential premises. The Company will report back to the Commission at the time of its next base rate case regarding the adoption of TOU-RD and its use as the default rate for newly constructed residential premises. (Proposed Agreement Provisions 20 & 21).

In its initial case, Georgia Power proposed to eliminate the R tariff as an option for customers in new premises. GIPL/Southface/Vote Solar stated in its brief that Georgia Power proposes to limit customer choice by transitioning a sizeable fraction of residential customers – those moving into new premises – away from its most widely used tariff (the standard R tariff). They argued further that the Company pushes this paradigm shift despite having done little in recent years to promote its time-varying rates and despite having no defined plans to equip customers with the tools and data needed to make informed decisions. Therefore, GIPL, Southface & Vote Solar recommended that the Commission reject Georgia Power's proposal to eliminate the

R tariff as an option for customers in new premises. GIPL/Southface/Vote Solar further recommended that the Commission "direct the Company and Staff to design a comprehensive, specific, and measurable plan to promote voluntary customer adoption of modern rate design that send accurate price signals, are cost-reflective and align utility and customer interests."

PIA Staff also opposed the Company's proposal to discontinue offering the R Rate to new premises after January 2020 arguing that as the monopoly utility provider in the service territory, eliminating a choice for customers is contrary to the public interest. PIA Staff recommended that if the Commission were to close Rate R for any residential customer, in keeping with the ratemaking principles of gradualism and customer satisfaction, PIA Staff proposed to either exempt existing (prior to January 2020) Georgia Power customers from this new Rate R foreclosure provision, even if they move to a new premises, or allow any existing Rate R customers in Georgia Power territory that are moving into new premises an ability to opt-in to Rate R.

The Commission finds that it is appropriate to maintain the R Tariff as a rate option available to all residential customers for the term of the ARP with the TOU-RD tariff becoming the default rate for newly constructed residential premises in 2021. Further, the Commission finds and concludes that it is reasonable to allow a collaborative process as outlined above.

19.

The Proposed Agreement also requires the Company to work with Commission Staff to develop options for customer access to usage data and submit those options to the PSC for approval. Stipulating Parties will be provided an opportunity to provide comments on the options proposed and upon approval, the Company will strive to implement the provisions of the plan no later than January 1, 2022. The cost for providing additional options for access to customer usage data shall be deferred as a regulatory asset and recovered in a future base rate proceeding. (Proposed Agreement Provision 22).

PIA Staff recommended that the Commission require the Company to continue its investigation of the costs and benefits of providing hourly usage information to its residential customers and within six months provide an updated cost estimate to provide hourly usage data to all residential customers.

GIPL/Southface/Vote Solar recommended that the Commission require Georgia Power to work with PIA Staff and interested Intervenors to develop a data access implementation plan and data privacy policy, and to submit the plan and policy to the Commission for approval by June 30, 2020 for implementation no later than January 1, 2021.

The Commission finds that the requirements in the Proposed Agreement sufficiently address the recommendations on this issue.

20.

The Proposed Agreement provides that within ninety (90) days of the Final Order in this docket, the Company, Georgia Watch, and Commission Staff shall collaborate on a process to consider potential options for the expansion of income qualified discount opportunities to assist customers. This process will allow for parties to provide input on the options to be considered. The Proposed Agreement further provides that within 270 days of the Final Order in this docket, the Company after having taken input from other parties will report back to the Commission on their findings and may recommend additional action. Any potential program options must consider cost impacts to non-participating customers as well as the impacts of any revenue erosion. (Proposed Agreement Provision 23).

The Commission approves the process set out in the Proposed Agreement.

21.

The Proposed Agreement provides that the Company agrees to further promote Project Share to customers and increase the Company's matching to 150% of customer contributions up to $1.5 million annually. (Proposed Agreement Provision 24).

The Commission approves the Company's promotion of and increased contribution to Project Share.

22.

The Proposed Agreement provides that the Electric Transportation ("ET") tariff shall be allocated 70% of the base rate increase in 2021 and 2022. The revenue deficiency for this adjustment shall be accounted for within the Governmental/Institutional tariff group. (Proposed Agreement Provision 25).

The Commission finds and concludes that this tariff change is reasonable.

23.

In accordance with the Proposed Agreement, the Time of Use – Medium Business ("TOU-MB") rate shall be made available to all food services and drinking places identified as 722 of the North American Classification System (NAICS). A franchise with multiple accounts shall no longer be an applicability requirement. Any existing customers on TOU-MB not qualifying as 722 will be considered grandfathered on TOU-MB an allowed to remain on the rate. During the term of the ARP, qualifying food services and drinking places will be accepted on TOU-MB on a first come, first allowed basis until the number of accounts on the rate equals 6,000. The rate will be reviewed in the next base rate case. Any revenue erosion from the TOU-MB rate conversion during the term of the ARP will be captured in a regulatory asset account and recovered through rates in 2021 and 2022. All revenue loss resulting from the implementation of this provision shall be recovered by the Company from the TOU- MB rate. (Agreement Provision 26).

GRA stated in their post hearing brief that it is unfair and anti-competitive for the TOU-MB rate schedule to only be offered to large chain restaurants. (GRA Post-Hearing Brief at p. 1). GRA also requested that the TOU-MB rate be frozen until the next rate case in order to move towards parity. (*Id*.).

The Commission concludes that by opening the TOU-MB rate schedule to all food service and drinking places identified as 722 of the NAICS, smaller restaurants will be able to be more competitive with larger chain restaurants. GRA stated in their brief that there are currently approximately 3,000 customers currently on the TOU-MB rate. (*Id.* at 2). By allowing approximately 3,000 more customers to join the rate, the Proposed Agreement allows for smaller restaurants to be more competitive while balancing the interests of other ratepayers. As such, the Commission finds this provision of the Proposed Agreement to be reasonable.

24.

The Proposed Agreement provides that the Company agrees to evaluate an enhanced demand response program for Industrial Customers (spinning reserves, etc.) to determine if such a program would provide any value to all customers. The Company will provide the results of the evaluation to interested Stipulating Parties within 180 days of the Order date. The Company's evaluation will include analysis quantifying the potential benefits and costs to interested customers including whether any additional steps are justified by the results of the evaluation. If interested Stipulating Parties and the Company agree that an enhanced demand response program brings value to all customers, the Company agrees to seek Commission approval for a pilot program at least 12 months prior to the 2022 IRP. (Agreement Provision 27).

The Commission finds and concludes that this evaluation process is reasonable.

25.

The Proposed Agreement provides that the tariff language changes proposed by the Company to the RTP Tariff in the Company's filing shall be modified as follows: The definition for "Existing Load" shall be defined as load previously served by Georgia Power and shall include load moved from one location to another provided that the operation at the new location is substantially identical to the operation at the former location. The definition of "New Load" shall mean load not defined as "Existing Load." "New Load" shall also include load at a location that has been vacant less than twenty-four months provided that the operation is not substantially identical to the previous operation at that location. Finally, CBL reductions shall be allowed to reflect the impact of equipment removal/replacement and energy efficiency improvements implemented during the initial Term of Contract that result in measurable reduction in electric power demand and/or energy usage, provided that the Company's financial requirements are met. This language shall be incorporated into the appropriate places within the RTP tariff. (Proposed Agreement Provision 28).

DOD/FEA requested that the Commission deny the Company's request to lengthen the time period for an RTP customer to establish a lower CBL without approved load removal. DOD/FEA stated that the increased time period requirement is unnecessary because a customer must remove itself from the RTP tariff for twelve months, which serves as sufficient credible commitment that it has achieved the reduced load.

RSM recommended that for every 1000 MW of solar in the system the Company utilize 150 MW of customer response via the marginal cost pricing mechanism already in place with its RTP rate. (RSM Brief at p. 1).

The Commission finds and concludes that the Proposed Agreement's modifications to the RTP Tariff language changes are reasonable. The proposal to extend the length of time a customer must stay off RTP before rejoining RTP and setting a new CBL is also approved.

26.

The Proposed Agreement provides that the Multiple Load Management ("MLM") rate shall be eliminated as proposed by the Company, and customers moving from MLM will be moved in a revenue neutral manner to the Time of Use – Revenue Neutral ("TOU-RN") tariff. If a customer on MLM with RTP prefers to move their CBL to a rate other than TOU-RN, they will be permitted to select any tariff for which they meet the applicability requirements and move their CBL to that rate in a revenue neutral manner. (Proposed Agreement Provision 29).

The Commission finds and concludes that this tariff change is reasonable.

27.

The Proposed Agreement provides that funds for electric vehicle infrastructure will be allowed as proposed by the Company with an additional $6 million per year to be invested in support of wire and transformer upgrades for customer sited charging stations. (Proposed Agreement Provision 30). The Commission finds and concludes that the projected capital and Operation & Maintenance ("O&M") costs associated with electric vehicle ("EV") infrastructure proposed in the Company's filing should be included in the Company's cost of service. In addition, the Company should invest an additional $6 million per year in support of wire and transformer upgrades for customer sited charging stations. Whether costs for electric vehicle charging facilities or costs for infrastructure supporting such facilities should be included in the Company's cost of service is a matter of policy to be decided by this Commission. This Commission finds that such costs must not be examined in isolation: EV charging stations serve as much more than an additional source of revenue for the Company or any other business for that matter. EV charging stations provide public benefits above and beyond dollars and cents. For example, the overall grid benefits from EV drivers who routinely shift their load and place a positive benefit onto the grid. In addition, evidence presented by the Company indicates that residential and business/workplace rebate programs have positive rate impact measure ("RIM") values, which helps all customers by putting downward pressure on rates.

The Sierra Club argued that the $6 million per year in spending is just, reasonable, and prudent. (Sierra Club Post Hearing Brief p. 13). The Sierra Club also agree that sufficient public charging infrastructure provides a "backbone of infrastructure" necessary to support the emerging demand for EVs. (Tr. 2648; Poroch Rebuttal at 34.)

PIA Staff opposed the inclusion of EV related spending in rate base and cost of service and asserted that "the [public] charging stations will not generate enough revenue to cover O&M expense and depreciation and allowing rate recovery would mean non-EV drivers would be subsidizing investments that only benefits EV-driving ratepayers." (Tr. 1228; Smith and Trokey Direct at 73).

The Commission concludes that this policy decision extends beyond cost considerations and accordingly, finds that allowing the proposed EV charging station costs, as well as the additional supporting infrastructure costs, into rate base strikes the right balance between the monetary and non-monetary benefits associated with EV infrastructure deployment.

28.

The Proposed Agreement provides that the method for bi directional metering utilized by Georgia Power under the Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act") O.C.G.A. § 46-3-51, to be considered as part of the PIA Staff review of the Company's methodology and computation of avoided cost in Docket No. 4822 that was provided for in the Commission's Final Order issued in Docket Nos. 42310 and 42311. It further provides that to the extent Parties continue to raise such issues, the Commission will consider the Company's bi-directional metering practice as part of that review. (Agreement Provision 31).

During the proceeding and in their Post Hearing Brief, GIPL/Southface/Vote Solar maintained that the Cogen Act required monthly netting. They argued that monthly netting allows solar customers to properly receive full value from their private investments. (GIPL/Southface/Vote Solar Post Hearing Brief p. 15).

GSEA/GSEIA stated that the Company's Renewable and Non-Renewable ("RNR") tariffs, including RNR-10 if approved, are consistently silent on netting and that since RNR tariffs never identified a netting methodology, the Company cannot credibly claim that its netting methodology was approved as a part thereof. GSEA/GSEIA urged the Commission to reject the Company's instantaneous netting methodology and direct it to implement monthly netting consistent with normal metering practices during the billing period as required by the Co-Gen Act.

Georgia Power stated that the Company's implementation of the RNR tariff is compliant with the Co-Gen Act and should not be overhauled to institute policy changes to increase payments to customer generators as argued by Intervenors.

The Commission finds and concludes that the Proposed Agreement should be modified to provide that the "Behind the Meter" netting period length shall be changed from instant to monthly

for the first 5000 rooftop solar ratepayers or until the new installed capacity reaches 32 MW, whichever comes first. Following that, any new rooftop solar ratepayers would be subject to the current scheme of instant net metering. This will be re-evaluated in the next rate case.

29.

The Commission finds that the Proposed Agreement should be modified to provide that the fee for Analog Meter Ratepayers shall be dropped by $1.00 per month. The Commission will reevaluate the fee and this change in the next rate case.

The Commission finds and concludes that this reduction to the analog meter fee is reasonable.

30.

In its filing, which the Proposed Agreement accepts by reference, the Company proposed to convert the basic service charge in the tariffs within the Domestic Group to a daily amount. Currently, a bill can be generated with the service period ranging from 25 to 36 days without being prorated. This means that customers that experience a 36-day bill period incur the same basic service charge as a customer whose bill only includes 25 days of service. Conversely, if a bill is calculated using a daily basic service charge amount, the result will be based on the exact number of days of service, which will make this portion of the bill more accurate and simpler for customer to understand. (Tr. 757).

PIA Staff stated that the Company had not justified its request to prorate the BSC on a daily basis. Currently, the BSC is the same for each month; it does not vary based on the number of days in the month. (Tr. 2919). PIA Staff contended the Commission should require the Company to continue the standard practice of 12 evenly monthly payments for customers who pay monthly bills. (PIA Staff Brief at p. 46).

GIPL/Southface/Vote Solar stated that the Commission should reject the Company's request to switch from a monthly BSC to a daily BSC. Changing to a daily basic service charge would "exacerbate monthly bill volatility, result in a charge that is less transparent and less understandable for customers," and the Company "did not identify any clear need for the change." Tr. 2082). Further, the Company stated that over the course of a year, any differences in billing period will even out-meaning, all customers will ultimately pay the same total amount in basic service charges without a switch to a daily charge. (Tr. 2920).

The Commission finds that converting the BSC in the tariffs within the Domestic Group to a daily amount is reasonable is thus accepted.

31.

Although PIA Staff accepted the Company's proposed $63.5 million for the projection of storm damage charges for the test year and ARP years, they recommended a review of the recovery

mechanisms and that the Company's storm damage costs be reviewed in detail. PIA Staff also adjusted the Company's estimate of the December 31, 2019 deferred storm damage cost balance using actual charges for January through June 2019 in place of the Company's estimates for those months. The adjustment resulted in a slightly lower December 31, 2019 balance, which PIA Staff recommended be amortized over a three-year period. (Tr. 1158; Smith and Trokey Direct at pp. 85-87).

PIA Staff's recommendation that the Company's storm damage costs be reviewed in a separate investigation apart from the rate case stems from the fact that the Company's deferred amount has built up to over $400 million and most of that from storms occurring in recent years since the Company's 2013 rate case. The Company argued that a separate review and audit is unnecessary because existing internal and external review channels provide sufficient opportunity for the Company and Commission to audit the Company's storm damage account balance.

DOD/FEA recommended that the Commission approve an annual deferred cost recovery mechanism and recovery rider for storm damage costs, rather than the past and proposed Company practice in which it incorporates storm damage recovery directly in base rates. (DOD/FEA Brief at p 9).

The Commission finds that it is appropriate to approve the continuation of the current ratemaking treatment of such costs.

32.

PIA Staff recommended that the Company's revenue requirement be adjusted by $272,000 on a retail jurisdictional basis to reflect interest credits on minimum bank balances stating that these interest credits offset its bank fees. The Company did not reflect these interest credits in its rate case filing because the amount of the credits is uncertain since it cannot exactly predict the minimum bank balances. (Tr. 309, 1226-27). PIA Staff argued that since the bank fees the Company must pay are included in revenue requirement and collected from ratepayers, it would be unfair for the Company to be able to keep the interest credits that offset the bank fees.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation is denied.

33.

The Company stated that the total compensation plan, including stock-based at-risk compensation is market competitive and appropriately balances operational with financial focus for both short-term and longer term to drive employee behavior in ways that balance the interests of customers and shareholders alike. (GPC Post Hearing Brief pp. 49-55). Furthermore, the Company stated that moving at-risk pay to base pay would not be in the best interest of customers, however, as it would encourage employees to focus solely on short-term operational performance with no balance or accountability to long-term operational costs and efficiencies. (*Id.*). Therefore,

the Company believes that stock-based compensation should be included in the Company's revenue requirements and recovered in retail rates.

PIA Staff stated in its post hearing brief that the Company incurs the costs of these incentive compensation programs in an effort to improve the Southern Company financial performance for the benefit of shareholders, not for the benefit of ratepayers. "For instance, the purpose of these incentives is not to improve customer service or meet other regulated utility service requirements. To the contrary, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each other. And the fact that maximizing shareholder value frequently does not serve the ratepayer interest of lower rates for the service shows the fatal flaw in the argument that these financial incentives should be seen as merely part of a compensation package, and as such, should be recovered from ratepayers."

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation to remove the stock compensation plan from rate base is denied.

In conjunction with its adjustment to remove stock-based compensation, PIA Staff recommended that the Company's proposed ARP payroll tax expense be reduced by $1.484 million, $1.629 million and $1.732 million in 2020, 2021 and 2022, respectively. (Tr. 1239, PIA Staff Exhibit 9).

For the same reasons that PIA Staff's adjustment to remove stock-based compensation was not adopted by the Commission, the corresponding payroll tax expense adjustment is denied.

34.

PIA Staff recommended removal of expenses related to Georgia Power's executive financial planning program, which provides personal financial planning, estate planning, investment advice and tax planning and preparation to Georgia Power's Chief Executive Officer, Chief Operating Officer, Vice-Presidents and Directors. (Tr. 1234). PIA Staff's position does not prohibit the Company from offering its program to top executives. The Company's position is that ratepayers should pay for this cost for its top executives as those executives provide value to the ratepayers. PIA Staff recommends that shareholders be held responsible for paying for the program because this program is not necessary for the provision of safe and reliable electric service.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation is denied.

35.

PIA Staff recommended that the Commission reject the Company's requested uncollectibles expense stating that it is inconsistent with its experience in recent years. Even

though the Company has incurred less than $12 million in uncollectibles expense in 2017 and 2018, it requested an uncollectibles expense of $13.445 million in the test year, $14.003 million in 2020 and 2021 and $14.004 million in 2022. (Tr. 1240). PIA Staff argued that the Company failed to identify a key driver for the inconsistency.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation is denied.

36.

PIA Staff proposed an adjustment to revenue requirement for property tax true-up. Georgia Power has booked a property tax true-up in 14 of the past 17 years. (Tr. 1235, 2718). Yet, Georgia Power declined to account for such a true-up in its rate case filing because it claimed that the true-up cannot be predicted with certainty. (Tr. 2715). PIA Staff argued that the Company's approach is inconsistent both with Commission precedent and with how the Company has addressed other items within this very rate case. The Commission adopted an adjustment for property tax refunds in the 2010 rate case (Docket No. 31958). Therefore, the PIA Staff recommended that the Commission adopt PIA Staff's recommended $2.604 million adjustment to reflect a reduction in the Company's revenue requirement equal to the 17-year average for property tax refunds received by Georgia Power.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation is denied.

37.

PIA Staff's proposed recommendation regarding sharing of responsibility for the CCR ARO amount for Plant Kraft and the benefits of donating Plant Kraft land to the Georgia Port Authority stems from the authorization received by the Company from the Commission, in Docket No. 36989, to donate a parcel of land at Plant Kraft to the Georgia Ports Authority. PIA Staff argued that both the State of Georgia (through the receipt of the land by the Ports Authority) and Georgia Power (through a boost to its reputation as a good corporate citizen) will benefit from the donation of the land. PIA Staff argued that ratepayers should receive a benefit as well. The Plant Kraft land that is to be donated includes the site of the coal ash pond which appears to have been remediated. In order to provide some benefit to ratepayers as well as the Company and the State, PIA Staff recommended that the Commission and the Company should consider applying some of the donation-related tax savings that would otherwise be assigned below-the-line to addressing the Plant Kraft ash pond clean-up cost. In the alternative, if the full benefit of donating that land is to be retained by shareholders, PIA Staff's alternative recommendation was that the related ash pond remediation costs also be allocated to shareholders. PIA Staff asserted that this is equitable because the clean-up appears to have increased the market value of the plant land that is to be donated and that it would be unfair for ratepayers to pay for the clean-up and shareholders reap

the full benefit of donating the land that increased in value as a result of the clean-up. (PIA Staff Brief p. 37)

The Company proposed to follow the accounting requirements and process outlined in the Commission's October 16, 2018 Order Approving Donation of Tract-1 Land at Plant Kraft in Docket No. 36989, which the Company argued approved the Company's donation and the proposed accounting treatment for the Plant Kraft land. See Order on Georgia Power Company's 2016 Annual Surveillance Report, Docket No. 36989 (Jan. 19, 2018) at 2.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, PIA Staff's recommendation is denied.

38.

The Company used the minimum distribution system ("MDS") methodology in its Cost of Service Study ("COSS") to separate customer-related distribution system costs from demand-related costs that customers place on the system. The Company explained that the MDS is a key input of its COSS as it separates the cost of line transformers, primary and secondary lines, and equipment, into demand-related costs, which are directly related to customer's peak load requirements, and customer-related costs, which are independent of customers' peak load requirements. Company Witness Vogt explained that Bonbright, NARUC, and several utilities around the country acknowledge MDS as an acceptable method for allocating customer-related distribution costs.

PIA Staff, GIPL/Southface/Vote Solar, and Sierra Club recommended that the Commission require that the Company use the Basic Customer Method instead of MDS. PIA Staff disagreed with the Company's use of MDS for determining distribution costs caused by the need to serve customers separate from customer demand placed on the system. Citing Bonbright, PIA Staff faults the MDS technique because it does not vary with the number of customers and loads customers with more fixed system costs. PIA Staff estimated that close to $8 of the $20.87/month customer costs calculated in the COSS are MDS related. PIA Staff recommended the Company remove the allocation of the MDS costs to customer service or strip out the MDS effects on the monthly basic service charge it proposes.

The Company, in its rebuttal testimony, argued that MDS is more comprehensive than the Basic Customer Method. According to the Company, MDS includes the costs identified using the Basic Customer Method, and also includes the cost of equipment necessary to provide safe and reliable service, which is not based on a customer's demand and should be allocated as customer-related. (See Tr. 2870.) The Company opposes classifying or collecting fixed customer-related costs through the variable energy portion of customer rates. The Company requests permission to continue relying upon the MDS methodology arguing that this approach yields a fair and equitable assignment of costs to customers.

Commission approval of the Settlement Agreement as modified allows for the Company's continued use of the MDS methodology to determine the customer-related portion of distribution costs.

39.

PIA Staff recommended that the Commission "require Georgia Power to perform an evaluation of the use of monthly coincident peaks to reflect more precisely the months where there is the potential for summer and winter peak demands to occur." PIA Staff further explained that "this could be done by utilization of an up to 8 CP approach, reflecting a proper balance of assignment of fixed costs to both summertime and wintertime peaks." (PIA Staff Brief at pp. 43-44).

The Company refutes the idea that a non-coincident peak is an inappropriate base for setting a demand charge. There are multiple demand costs to cover in a demand charge, including distribution costs, which are based on a non-coincident peak. (Id.) Using the Company's existing time of use price signal keeps the rate simpler and easy to understand and helps customers avoid extreme bill swings in summer months. (Id.) (Company Brief at p. 70).

The Commission accepts the Settlement Agreement as modified and requires no changes at this time as it relates to this issue.

40.

PIA Staff requested that the Commission "order the Company to revise its wintertime declining block rates to a flat energy rate. Just as the inclining block rate structure during the summer sends a price signal that as consumption increases, so likely do system costs, a declining block rate structure sends the opposite price signal that as consumption increases, system costs decline." (PIA Staff Post Hearing Brief at p. 44).

In response to PIA Staff, the Company stated that it "originally designed the residential rate to reflect the seasonality of costs to serve residential customers." (Tr. 2889.) "The increasing price blocks in June through September reflect the fact that the Company's costs are higher in the summer months. (Id.) The declining block structure in the non-summer months recognizes that off peak costs are lower and provides price signals to reflect this reality. (Id.) The prices are set to more than cover the Company's marginal costs and resulting revenues place downward pressure on rates for all customers. (Id.) The Commission should reject requests to change the declining block rate structure." (Company Brief at p. 61).

GIPL/Southface/Vote Solar witnesses argued that Georgia Power should eliminate the non-summer declining block portion and replace it with a flat tariff.

The Commission finds that non-summer declining block portion is reasonable as filed and thus any change is denied.

41.

The Company has proposed several changes in the wording of its Flat-5 tariff. PIA Staff stated that the Company's proposed changes would remove the 12-month history requirement. The effect would require "new Georgia Power customers, when establishing their account, to choose the FlatBill tariff and be charged a monthly bill based on that premises, another household's, previous 12- month usage." (Tr. 2924). PIA Staff recommended that "the Commission reject these proposed revisions because the customer could end up with a higher or lower bill as compared to the Residential service rate because usage is not based on that resident's actual historical 12-month usage." (PIA Staff Brief at p. 49).

GIPL/Southface/Vote Solar believe that "FlatBill encourages wasteful use of electric service contrary to basic principles of rate design." GIPL/Southface/Vote Solar go on to argue that the "flat monthly amount is determined by billing under the R tariff (plus a "risk" adder of up to 10%), the very tariff the Company considers "antiquated" and proposes to move away from." (Tr. 1955). GIPL/Southface/Vote Solar further recommend that the Commission "reject these less than 'modern' proposals." (GIPL/Southface/Vote Solar Brief at pp. 8-11).

In accordance with the Commission's approval of the Settlement Agreement as Modified, the Company's proposed changes are accepted.

42.

The Commission finds that the date on which the rates pursuant to the Settlement Agreement as Modified shall become effective is January 1, 2020.

43.

The Commission finds that a three-year term for the Settlement Agreement as Modified ending December 31, 2022 is reasonable. By July 1, 2022, the Company shall file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case. The test period utilized by the Company in its rate case filing shall be from August 1, 2022 to July 31, 2023. The Company may propose to continue, modify or discontinue this Alternate Rate Plan. The Company shall also file projected revenue requirements for calendar years 2023, 2024, and 2025. (Proposed Agreement Provision 32).

CONCLUSIONS OF LAW

1.

The Georgia Public Service Commission has general ratemaking jurisdiction over Georgia Power Company under O.C.G.A. Ch. 2, T. 46. The Georgia Public Service Commission has general supervision over electric light and power companies. O.C.G.A. §§ 46-2-20(a) and 46-2-21. The Commission has "exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm, or corporation subject to its jurisdiction." O.C.G.A. § 26-2-23; see also O.C.G.A. §§ 46-1-1(5), 46-2-24, 46-2-25, 46-2-26.1, and 46-2-26.2.

2.

The Settlement Agreement as Modified complies with the test year statute for electric utilities which provides in relevant part:

> In any proceeding to determine the rates to be charged by an electric utility, the electric utility shall file jurisdictionally allocated cost of service data on the basis of a test period, and the commission shall utilize a test period, consisting of actual data for the most recent 12- month period for which data are available, fully adjusted separately to reflect estimated operations during the 12 months following the utility's proposed effective date of the rates. After the initial filing and until new rates go into effect, the utility shall file actual cost of service data as they become available for each month following the actual data which were filed. The utility shall have the burden of explaining and supporting the reasonableness of all estimates and adjustments contained in its cost of service data.

(O.C.G.A. § 46-2-26.1(b))

Georgia Power filed the requisite data on the basis of a test period, and the Settlement Agreement as Modified uses the test period as a starting point and then makes necessary and appropriate adjustments to reflect operations during the 12 months following the utility's proposed effective date of the rate. The test period data serves as the benchmark from which adjustments are made for each year of the Alternative Rate Plan. This methodology is consistent both with the statute and with Commission precedent in rate case proceedings dating back to 1998.

3.

The rates resulting from the Settlement Agreement as Modified are fair, just and reasonable. By adopting the Settlement Agreement as Modified, the Commission retains its jurisdiction to ensure that the Company's rates are fair, just and reasonable.

4.

The remaining terms and conditions of the Settlement Agreement as Modified are reasonable and appropriate. By adopting the Settlement Agreement as Modified, the Commission adopts a reasonable resolution of the remaining issues in this docket.

5.

The Commission retains its jurisdiction to ensure that the Company abides by and implements the rates, terms and conditions set forth in the Settlement Agreement as Modified adopted herein, and to issue such further order or orders as this Commission may deem proper.

III. ORDERING PARAGRAPHS

WHEREFORE, IT IS ORDERED, that the Settlement Agreement as Modified shall be and the same hereby is adopted, that its terms and conditions are fully incorporated herein, and that Georgia Power Company shall comply with said terms and conditions.

ORDERED FURTHER, that the terms and conditions set forth in the Settlement Agreement as modified are just and reasonable and shall take effect for service rendered from and after January 1, 2020.

ORDERED FURTHER, that the tariffs implemented by Georgia Power to implement the aforesaid annual rate increase in the years 2020, the adjustments contemplated in 2021 and 2022, as well as the terms and conditions of the Settlement Agreement as Modified shall be subject to review by the Commission to ensure that such tariffs, as implemented, are proper and just.

ORDERED FURTHER, that for purposes of the rate increase in the year 2020, Georgia Power shall file compliance tariffs within 30 days of the issuance of this Order, reflecting rates to implement the rate increases ordered herein. These tariffs shall reflect the rate allocations adopted in this Order, and shall be subject to the Commission's review for final approval.

ORDERED FURTHER, that for purposes of the rate adjustments specified in the Settlement Agreement as Modified, the Company shall make compliance filings of the updated tariffs at least 90 days prior to the effective date of the tariffs. Compliance filings shall be served upon all parties of record to this proceeding. Upon receipt of such compliance filing, parties may offer input relative to the filing to the Commission.

ORDERED FURTHER, that all findings, conclusions and decisions contained within the preceding sections of this Order are adopted as findings of fact, conclusions of law, and decisions of regulatory policy of this Commission.

ORDERED FURTHER, that jurisdiction over this proceeding is expressly retained for the purpose of entering such further order or orders as this Commission may deem proper.

ORDERED FURTHER, any motion for reconsideration, rehearing, or oral argument shall not stay the effectiveness of this order unless expressly ordered by the Commission.

The above by action of the Commission in Administrative Session on the 17th of December, 2019, as clarified by action of the Commission in Administrative Session on the 4th of February 2020.

_____	_____
Reece McAlister	Chuck Eaton
Executive Secretary	Chairman
_____	_____
Date	Date

VECC Interrogatory #18

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1 Concentric Report

a) Did the authors analyze bond yield spreads in their comparative analysis of other utilities? If so please provide that analysis.

Response

Response Prepared by Concentric Energy Advisors

No, bond yield spreads were not analyzed by Concentric in its report. Bond yield spreads are often considered in an ROE analysis, which was not part of Concentric's scope of work or recommendation.

CCC Interrogatory #29

Interrogatory

Reference: Exhibit C2/T1/S1/ pp. 2-3; Ex. C2/T1/S1 Attachment 3 Table 1

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

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

Response

a) The requested table is provided at Attachment 1, reflecting actual year-end 2020 information including the adjustment to nuclear liabilities for changes to the Pickering station EOL dates.

Numbers may not add due to rounding.

Updated: 2021-07-09
EB-2020-0290
Exhibit L
C2-01-CCC-029
Attachment 1
Table 1

Table 1
Projected Revenue Requirement Impact of OPG's Nuclear Liabilities Inclusive of Impact Resulting from Optimization of Pickering Station End-of-Life Dates ($M)
Years Ending December 31, 2016 to 2026

Line No.	Description	Note	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	PRESCRIBED FACILITIES												
1	**Depreciation of Asset Retirement Costs**	6	50.3	74.1	82.2	82.2	82.2	80.2	80.2	80.2	80.2	3.4	3.4
2	**Used Fuel Storage and Disposal Variable Expenses**		61.0	45.1	51.8	65.0	55.2	65.7	62.9	74.7	78.5	58.6	57.5
3	**Low & Intermediate Level Waste Management Variable Expenses**		3.2	11.3	8.9	5.9	8.3	17.8	12.9	15.8	15.6	9.1	4.7
	Return on ARC in Rate Base:												
4	**Return on Rate Base at Weighted Average Accretion Rate**	5	42.2	25.0	28.1	23.9	19.9	18.3	8.6	0.0	0.0	0.0	0.0
5	**Return on Rate Base at Weighted Average Cost of Capital**	1	0.0	0.0	0.0	0.0	0.0	0.0	7.2	12.8	8.1	5.7	5.5
6	**Pre-Tax Revenue Requirement Impact**		156.7	155.5	170.9	177.0	165.6	182.0	171.7	183.4	182.4	76.7	71.2
7	**Income Tax Impact**	2	(36.8)	(25.3)	(11.0)	(9.1)	(36.7)	(13.8)	(86.6)	(25.2)	(29.3)	(34.4)	(12.6)
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		119.9	130.2	159.9	167.9	128.8	168.2	85.1	158.2	153.1	42.4	58.5
	BRUCE FACILITIES												
9	**Depreciation of Asset Retirement Costs**	7	100.2	68.0	69.2	69.2	69.2	69.4	69.4	69.4	69.4	69.4	69.4
10	**Used Fuel Storage and Disposal Variable Expenses**		66.9	57.3	63.6	64.7	60.1	79.6	80.1	95.2	86.0	96.9	79.8
11	**Low & Intermediate Level Waste Management Variable Expenses**		2.5	2.5	2.5	2.6	4.0	5.6	3.7	4.9	5.2	4.3	5.3
12	**Accretion Expense**		511.9	459.9	470.6	487.8	504.1	520.1	537.5	556.7	576.4	599.0	622.9
13	**Less: Segregated Fund Earnings (Losses)**		374.9	393.8	406.5	423.8	439.0	444.4	452.6	462.0	475.1	491.0	510.3
14	**Impact on Bruce Facilities' Income Taxes**	3	(76.7)	(48.5)	(49.9)	(50.1)	(49.6)	(57.6)	(59.6)	(66.1)	(65.5)	(69.7)	(66.8)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		230.0	145.4	149.6	150.4	148.7	172.7	178.7	198.2	196.5	209.1	200.4
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	4	76.7	48.5	49.9	50.1	49.6	57.6	59.6	66.1	65.5	69.7	66.8
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		306.6	193.9	199.4	200.5	198.3	230.3	238.3	264.3	262.0	278.7	267.2
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites** (line 8 + line 17)		426.5	324.1	359.3	368.4	327.1	398.5	323.3	422.5	415.1	321.1	325.7

Notes:
See Table 1a for notes.

Numbers may not add due to rounding.

Updated: 2021-07-09
EB-2020-0290
Exhibit L
C2-01-CCC-029
Attachment 1
Table 1a

Table 1a
Projected Revenue Requirement Impact of OPG's Nuclear Liabilities Inclusive of Impact Resulting from Optimization of Pickering Station End-of-Life Dates ($M)
Years Ending December 31, 2016 to 2026
Notes to Table 1

Notes:

1 If average Unfunded Nuclear Liabilities (UNL) is less than average Asset Retirement Costs (ARC) for the prescribed facilities, the funded portion of average ARC (i.e. the amount by which average ARC exceeds average UNL) earns WACC as follows:

Table to Note 1

Line No.	Year	Average ARC ($M)	Average UNL ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC	(c) x (d) if >0 Return on Rate Base ($M)	WACC Reference
		(a)	(b)	(c)	(d)	(e)	
6a	2021	376.3	431.6	(55.3)	6.43%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 15
7a	2022	295.8	176.3	119.5	5.98%	7.2	Ex. C1-1-1 Table 5
8a	2023	215.6	0.0	215.6	5.93%	12.8	Ex. C1-1-1 Table 4
9a	2024	135.7	0.0	135.7	5.99%	8.1	Ex. C1-1-1 Table 3
10a	2025	94.2	0.0	94.2	6.01%	5.7	Ex. C1-1-1 Table 2
11a	2026	90.8	0.0	90.8	6.01%	5.5	Ex. C1-1-1 Table 1

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1b	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Table 1, line 6)	182.2	172.8	183.6	181.8	76.7	71.2
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities	102.5	244.4	100.6	100.6	0.0	0.0
3b	Expenditures for Used Fuel, Waste Management & Decommissioning	208.2	269.6	262.7	306.1	463.9	638.4
4b	Disbursements from Nuclear Segregated Funds	(87.5)	(82.5)	(104.3)	(136.4)	(284.2)	(529.3)
5b	Net Increase in Regulatory Taxable Income (line 1b - line 2b - line 3b - line 4b)	(41.1)	(258.7)	(75.4)	(88.5)	(103.1)	(37.9)
6b	Income Tax Rate (Ex. F4-2-1 Table 3, line 31 and Ex. F4-2-1 Table 3a, line 29)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
7b	Income Tax Impact (line 5b x line 6b / (1 - line 6b))	(13.7)	(86.2)	(25.1)	(29.5)	(34.4)	(12.6)

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 3 ($M)

Line No.	Item	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1c	Increase in Temporary Differences (Ex. C2-1-1 Table 1, lines 9 through 13)	230.3	238.3	264.3	262.0	278.7	267.2
2c	Income Tax Rate (Ex. G2-2-1 Table 7, line 19 and Ex. G2-2-1 Table 8, line 19)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
3c	Impact on Bruce Facilities' Income Taxes (line 1c x line 2c)	(57.6)	(59.6)	(66.1)	(65.5)	(69.7)	(66.8)

4 Income tax rates are from Ex. F4-2-1 Table 3, line 32 (2016-2021), and Ex. F4-2-1 Table 3a, line 31 (2022-2026).

5 From Ex. L-F4-01-Staff-271, Att. 1, Table 2b, Note 4, line 4d.

6 Per Ex. L-F4-01-Staff-271, Att. 1, Table 2a, Note 2, col. (d): line 2e for 2021; line 2h for 2022; line 2k for 2023; line 2n for 2024; line 2q for 2025; and 2t for 2026.

7 Per Ex. L-F4-01-Staff-271, Att. 1, Table 3a, Note 2, col. (d): line 2e for 2021; line 2h for 2022; line 2k for 2023; line 2n for 2024; line 2q for 2025; and 2t for 2026.

CCC Interrogatory #30

Interrogatory

Reference: Exhibit C2/T1/S1/ Attachment 2, p. 10, 33, 176; Ex. C1/T1/S1 Attachment 3 Table 1.

We found a wide range of practices with respect to nuclear decommissioning cost recovery. We have organized the practices we identified into four broad methodologies, as follows:

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

Based on a flow through cost

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

Screening Analysis

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

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

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

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

Response

a) to d)

OPG consulted with KPMG in preparing the below response, with which KPMG is in agreement.

The flow through cost method was not further analyzed because it does not apply to OPG's circumstances. As defined in the Nuclear Liability Cost Recovery Jurisdictional Study ("Study"), the method only applies where a utility does not hold the obligation for nuclear decommissioning or nuclear waste management but rather pays a levy to a third party underwriting the obligation, and in turn directly "passes" this levy on to customers.

For example, in Section 27, page 165, the Study provides some examples that are indicative of the circumstances where the flow through cost method is applicable:

> A very significant consideration in regard to US practice is the fact that the US DOE has accepted responsibility for the processing and long-term storage of spent fuel. In return, the US DOE collected fees from nuclear operators. These fees have been passed along to consumers and recovered through various mechanisms. The role of the US DOE significantly reduces the scope of activities that US nuclear operators need to provide for in their own recoveries for decommissioning.

In contrast, under the Canadian regime, OPG is responsible for decommissioning of its nuclear facilities and for the long-term management of its spent nuclear fuel and other irradiated materials. Hence, it could not be subject to the flow through cost method.

CCC Interrogatory #31

Interrogatory

Reference: Exhibit C2/T1/S1/ pp. 18, 19.

Through the calculation of regulatory income taxes for the prescribed facilities, the nuclear revenue requirement includes income tax impacts associated with the above cost elements for the nuclear liabilities, as well as the tax impacts of the prescribed facilities' contributions to the segregated funds, expenditures on nuclear liabilities and disbursements from the segregated funds.

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

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

Response

Refer to Ex. C2-01-CCC-030.

Energy Probe Interrogatory #14

Interrogatory

Reference:
Exhibit C2, Tab 1, Schedule 1, Table 1; Attachment 2, KPMG Jurisdictional Review, Pages 140, 180, Section 24

Preamble: "For the Prescribed Regulated facilities, the recovery from ratepayers would be over the operating life of the power plant. (KPMG)."

a) Please explain the reason for the decline in Nuclear Liabilities (Pickering, Darlington Prescribed facilities) ARC costs starting in 2023 (Table 1, line 1).

b) Why is the amount only $3.6 million in 2026?

c) Why is there a drop in the Used Fuel Storage and Low and Intermediate Level Waste Management expense in 2024 and 2025?

d) Given the shut-down of Pickering NGS has the recovery of its Decommissioning Costs been completed or does this and fuel storage costs continue beyond the life of the plant? If so, describe how are the contributions in rates to be calculated?

Response

a) As discussed at Ex. C2-1-1, p. 1, lines 24-27 and p. 22, lines 18-21, the decline in nuclear liabilities impact for the prescribed facilities in 2023 onwards is primarily due to the depreciation of asset retirement costs related to Pickering NGS based on accounting end-of-life dates reflected in the application.

b) Refer to part a).

c) OPG assumes the question is intended to refer to the decline in the cited expenses at lines 2 and 3 of Ex. C2-1-1, Table 1 in 2025 and 2026, rather than 2024 and 2025. This decline is due to the planned shutdown of Pickering NGS units based on OPG's optimized shutdown plan for the station, discussed at Ex. F2-1-1, Section 4.0.

d) Under the OEB-approved methodology for the nuclear liabilities for the prescribed facilities, OPG does not expect a need for recovery of costs related to Pickering NGS following the station's end of life, subject to any future adjustments to the cost estimates for the nuclear liabilities that may be recorded as an increase or decrease

in the asset retirement obligation related to the station, in accordance with US GAAP. The impact of such adjustments could either decrease or increase revenue requirement recovery post station end of life. This accords with O. Reg. 53/05, s. 6(2)8 that requires the OEB to ensure that OPG recovers the revenue requirement impact of its nuclear decommissioning and nuclear used fuel and waste management liability arising from the current approved ONFA reference plan. At this time, OPG has not developed a specific proposal on the manner in which any such future impact would be reflected in subsequent revenue requirement calculations based on the OEB-approved methodology.

Additionally, OPG expects that the benefit of income tax deductions for ongoing cash expenditures on nuclear liabilities related to Pickering NGS, net of receipts from the nuclear segregated funds, as well as of any future contributions to the nuclear segregated funds that may be required related to Pickering NGS post station end of life will continue to be included in subsequent nuclear revenue requirement calculations.

SEC Interrogatory #47

Interrogatory

Reference: C2-1-1, p.1

Please describe in detail all actions OPG can take to ameliorate the $1,192.1 million cost associated with the Bruce facilities over the test period.

Response

The question cites the impact that represents the cost of nuclear liabilities related to the Bruce facilities over the IR Term, determined in accordance with US GAAP under the OEB-approved methodology. This methodology was originally established by the OEB in EB-2007-0905 based on the requirements of O. Reg. 53/05, sections 6(2)8, 6(2)9 and 6(2)10. Given the requirements of O. Reg. 53/05, OPG does not have discretion over the recovery of this amount, which is based on the liabilities arising from the current approved ONFA reference plan. As in other parts of the business, OPG will continue to pursue efficiencies in safely performing nuclear waste management activities that underpin nuclear liabilities.

SEC Interrogatory #48

Interrogatory

Reference: C2-1-1, p.3

Please provide the 2020 audited financials of OPG as soon as they are available.

Response

Refer to Ex. L-A2-01-Staff-015.

Board Staff Interrogatory #74

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG stated that as a result of the Saugeen Ojibway Nation (SON) vote to not support the proposed permanent emplacement of low and intermediate level waste (L&ILW) into a separate deep geologic repository adjacent to the Western Waste Management Facility, OPG is exploring alternative solutions for the safe long-term management of L&ILW. Due to significant inherent uncertainties associated with potential alternative solutions, no adjustments to OPG's estimate of nuclear liabilities have been made as a result of the vote, in accordance with US GAAP and the ONFA.

Question(s):

a) Please discuss the materiality and potential magnitude of an adjustment to nuclear liabilities resulting from the SON vote, despite the inherent uncertainties associated with alternatives.

b) Please indicate when OPG expects to decide upon a solution for the safe, long-term management of L&ILW referenced above.

c) Please explain OPG's proposal for the adjustment to nuclear liabilities when a solution is decided upon.

Response

a) and b)

Although OPG expects that a form of updated financial planning assumption related to the solution for the safe, long-term management of L&ILW may need to be considered for the purposes of the 2022-2026 ONFA Reference Plan, OPG is unable to speculate on the potential magnitude of, or timing for a decision upon such an alternative solution at the present time. The 2022-2026 ONFA Reference Plan is currently under development and will be subject to approval by the Province of Ontario.

c) OPG expects that the revenue requirement impact for the prescribed facilities of any adjustment to nuclear liabilities arising from an approved ONFA reference plan that is not reflected in the approved payment amounts, including any adjustment related to a solution for the safe, long-term management of L&ILW, will be recorded in the Nuclear Liability Deferral Account. Similarly, OPG expects that the impact of any such adjustment related to the Bruce facilities will be recorded in the Bruce Lease Net Revenues Variance Account.

Board Staff Interrogatory #75

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 6

Preamble:

OPG explained that the initial value and each subsequent adjustment to the asset retirement obligation (ARO) are known as tranches. OPG also explained that the discount rate applied to each tranche is the credit adjusted risk-free rate, which is the Province of Ontario long-term bond yield rate, as at the date of each upward revision to the ARO.

Question(s):

a) Please explain any discretion or judgment management applies to select the discount rate for each tranche.

b) Please provide a table showing the calculation of the weighted average accretion rate, showing each of the nine tranches and the applicable discount rate. Please also provide the calculation of the weighted average accretion rate, including the newest tranche to reflect the change in Pickering end-of-life (EOL) effective December 31, 2020.

c) For the newest tranche(s) reflecting the change in Pickering EOL effective December 31, 2020, please explain whether there have been any changes to the methodology or assumptions used by management from those used in determining the discount rates for the previous nine tranches. Please provide supporting rationale for any changes.

Response

a) As discussed at Ex. C2-1-1, p. 6, lines 16-24, under US GAAP, upward revisions in the amount of undiscounted estimated cash flows underlying the asset retirement obligation (ARO) determined using a present value technique must be discounted using a current credited-adjusted risk-free rate. Downward revisions in the amount of undiscounted estimated cash flows underlying the ARO determined using a present value technique must be discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized (i.e. historical rate reflected

in the existing obligation). OPG has consistently used a Province of Ontario long bond yield rate to determine its credit-adjusted risk free rate (for example, see EB-2012-0002 Ex. L-1-7 SEC-12, p. 2, lines 25-30 and EB-2016-0152 Ex. L-8.2-1 Staff-207). Provincial long bonds typically range from 20 to 30 years. Yields on provincial long bonds are used to reflect the long-term nature and credit risk of the expected future cash flows. OPG selects the Province of Ontario long bond yield that it determines has sufficient liquidity. If there are multiple similarly dated long bonds, preference is given to the most liquid bond.

b) Attachment 1, Table 1 provides the calculation of the weighted average accretion rate reflected in the revenue requirement as filed, which was performed as of the most recent completed year at the time of preparing the application, being year-end 2019. Attachment 1, Table 2 provides the same calculation as of year-end 2020, inclusive of the ARO adjustment related to the changes in Pickering EOL dates effective December 31, 2020.

c) There were no changes to the methodology or assumptions used to determine the discount rate for the newest tranche of the ARO representing the year-end 2020 adjustment resulting from the changes in Pickering EOL dates effective December 31, 2020.

Calculation of Weighted Average Accretion Rate - As at December 31, 2019 [1]

Line No.	Asset Retirement Obligation Tranche[2]	Year-end Balance ($M) (a)	Weighting (b)	Accretion Rate (c)	Weighted Average Accretion Rate (d) = (b) x (c)
1	Tranche 1	$13,072	60%	5.75%	3.45%
2	Tranche 2	$3,254	15%	4.60%	0.69%
3	Tranche 3	$862	4%	4.80%	0.19%
4	Tranche 4	($64)	0%	3.43%	-0.01%
5	Tranche 5	$1,660	8%	3.50%	0.27%
6	Tranche 6	$3,915	18%	3.21%	0.58%
7	Tranche 7	($1,624)	-7%	4.95%	-0.37%
8	Tranche 8	$115	1%	3.20%	0.02%
9	Tranche 9	$582	3%	2.94%	0.08%
10	**Total/Weighted average as at year-end**[3]	**$21,771**	100%		**4.89%**

Notes:

1 Numbers may not calculate due to rounding

2 Tranches correspond to the following: Tranche 1 = ARO recorded prior to December 31, 2006; Tranche 2 = ARO recorded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan; Tranche 3 = ARO recorded on December 31, 2010 in relation to the decision related to the Darlington refurbishment project; Tranche 4 = ARO recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan; Tranche 5 = ARO recorded on December 31, 2012 arising from the approved 2012 ONFA Reference Plan; Tranche 6 = ARO recorded on December 31, 2015 to reflect changes in station end-of-life dates (mainly Bruce); Tranche 7 = ARO recorded on December 31, 2016 arising from the approved 2017 ONFA Reference Plan; Tranche 8 = variables expenses recorded subsequent to Tranche 7; Tranche 9 = ARO recorded on December 31, 2017 to reflect changes in Pickering end-of-life dates.

3 Represents OPG's total nuclear ARO excluding consolidation adjustments

Calculation of Weighted Average Accretion Rate - As at December 31, 2020 [1]

Line No.	Asset Retirement Obligation Tranche[2]	Year-end Balance ($M) (a)	Weighting (b)	Accretion Rate (c)	Weighted Average Accretion Rate (d) = (b) x (c)
1	Tranche 1	$13,270	59%	5.75%	3.38%
2	Tranche 2	$3,495	15%	4.60%	0.71%
3	Tranche 3	$1,072	5%	4.80%	0.23%
4	Tranche 4	($242)	-1%	3.43%	-0.04%
5	Tranche 5	$1,573	7%	3.50%	0.24%
6	Tranche 6	$4,219	19%	3.21%	0.60%
7	Tranche 7	($1,723)	-8%	4.95%	-0.38%
8	Tranche 8	$118	1%	3.20%	0.02%
9	Tranche 9	$759	3%	2.94%	0.10%
10	Tranche 10	$64	0%	2.01%	0.01%
11	**Total/Weighted average as at year-end**[3]	**$22,605**	100%		**4.86%**

Notes:

1 Numbers may not calculate due to rounding

2 Tranches correspond to the following: Tranche 1 = ARO recorded prior to December 31, 2006; Tranche 2 = ARO recorded on December 31, 2006 arising from the approved 2006 ONFA Reference Plan; Tranche 3 = ARO recorded on December 31, 2010 in relation to the decision related to the Darlington refurbishment project; Tranche 4 = ARO recorded on December 31, 2011 arising from the approved 2012 ONFA Reference Plan; Tranche 5 = ARO recorded on December 31, 2012 arising from the approved 2012 ONFA Reference Plan; Tranche 6 = ARO recorded on December 31, 2015 to reflect changes in station end-of-life dates (mainly Bruce); Tranche 7 = ARO recorded on December 31, 2016 arising from the approved 2017 ONFA Reference Plan; Tranche 8 = variables expenses recorded subsequent to Tranche 7; Tranche 9 = ARO recorded on December 31, 2017 to reflect changes in Pickering end-of-life dates; Tranche 10 = ARO recorded on December 31, 2020 to reflect changes in Pickering Units 1 & 4 end-of-life dates.

3 Represents OPG's total nuclear ARO excluding consolidation adjustments

Board Staff Interrogatory #76

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / pp. 6, 9,12

Preamble:

OPG stated that in accordance with US GAAP, the discount rate used for each ARO tranche is determined using the credit adjusted risk-free rate. OPG also stated that the discount rate used to calculate the funding liabilities is determined in accordance with the ONFA, which is set at 3.25% real rate of return plus the long-term change in the Ontario Consumer Price Index (CPI), equating to 5.15% per the 2017 ONFA Reference plan. This is also the long-term target rate of return on the segregated funds.

Question(s):

a) Please provide a table showing the discount rate for each tranche, the annual weighted average accretion rate, and the annual discount rate used to calculate funding liabilities in accordance with ONFA from the first year OPG has recovered nuclear liabilities in the payment amounts to 2026.

b) Please provide supporting rationale for why the ONFA sets the annual discount rate used to calculate funding liabilities to be 3.25% real rate of return plus the long-term change in the Ontario CPI.

c) Please provide OPG's view on the appropriateness of the discount rate used in calculating the funding liabilities. Please discuss OPG's view regarding why the ONFA sets the discount rate for the funding of liabilities to be the same as the guaranteed rate of return for fund earnings (i.e. the guaranteed rate of return for the portion of the Used Fuel Segregated Fund (UFF) attributed to the first 2.23 million used fuel bundles).

d) Please explain OPG's position regarding whether it is appropriate or not to apply the same discount rate used for calculating funding liabilities as is used for the ARO.

Response

a) The discount rate for each tranche of the ARO is provided in Ex. L-C2-01-Staff-075, Attachment 1.

The chart below provides the weighted average accretion rate (or equivalent) applied in setting OPG's payment amounts and the discount rate used to calculate funding liabilities under the applicable ONFA reference plan, by year, for the period from 2005 to 2026. For the period from April 1, 2005 to March 31, 2008, OPG was subject to interim rates that were set pursuant to O. Reg. 53/05.

Line No.		2005	2006	2007	2008	2009	2010	2011	2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Weighted Average Accretion Rates[1]	5.39%	5.26%	5.30%	5.60%	5.60%	5.60%	5.58%	5.58%
2	ONFA Discount Rate	5.75%	5.75%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%
		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3	Weighted Average Accretion Rates[1]	5.58%	5.37%	5.37%	5.37%	4.95%	4.95%	4.95%	4.95%
4	ONFA Discount Rate	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%
		2021	**2022**	**2023**	**2024**	**2025**	**2026**		
		(a)	(b)	(c)	(d)	(e)	(f)		
5	Weighted Average Accretion Rates[1]	4.95%	4.89%	4.89%	4.89%	4.89%	4.89%		
6	ONFA Discount Rate	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%		

Notes:

Weighted average accretion rates per the following:
2005-2007 from EB-2007-0905, Ex. H1-1-3. Equal to the proxy cost of capital rates (based on 5.0% ROE and actual cost of debt rates) for the April 1, 2005 to March 31, 2008 period covered by interim rates set under O. Reg. 53/05.
2008-2010 from EB-2007-0905 Payment Amounts Order, App. A, Table 4b, line 7, col. (c).
2011-2013 from EB-2010-0008 Payment Amounts Order, App. A, Table 4b, line 7, col. (c).
2014-2016 from EB-2013-0321 Payment Amounts Order, App. A, Table 5b, line 7, col. (c).
2017-2021 from EB-2016-0152 Payment Amounts Order, App. A, Table 11, line 7, col. (c).
2022-2026 Ex. C1-1-1, Tables 1 to 5, line 7, col. (c).

b) The discount rate was an outcome of a contracting process between OPG and the Province of Ontario to establish the ONFA in 2003.

c) Refer to part d) below.

The discount rate used to calculate the funding liabilities in accordance with the ONFA is not necessarily the same, in nominal terms, as the guaranteed rate of return on the portion of the UFF attributed to the first 2.23 million used fuel bundles in a given period. The former is based on a real rate of 3.25% plus the long-term change in the Ontario consumer price index ("CPI") as determined for each approved ONFA reference plan, while the latter is based on a real rate of 3.25% plus the annual change in the Ontario CPI.

d) Absent a change to the ONFA, OPG could not apply any other discount rate than what is specified in the ONFA for purposes of determining its funding liabilities. To align with how the funding liabilities are determined, OPG uses the discount rate specified in the ONFA as the target rate of return for the nuclear segregated funds.

Board Staff Interrogatory #77

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / pp. 5, 9

Preamble:

OPG stated that the baseline cost estimates underpinning the ARO are those developed through the ONFA Reference Plan update process.

OPG also stated that the ONFA funding liabilities reflect a lifecycle view of nuclear wastes forecast over the operating span of OPG's nuclear generating facilities, including wastes not yet generated. However, the ARO considers the committed portion of the costs for OPG's nuclear liabilities, which includes lifetime variable costs associated with the wastes generated to date but excludes such costs for wastes yet to be generated.

Question(s):

Aside from the nuclear wastes not yet generated, please explain whether there are any other differences between the cost estimates unpinning the ARO and that in the ONFA Reference Plan. If so, please identify and explain each of these differences and how they differ between the ONFA and ARO's cost estimates.

Response

Aside from the different treatment of nuclear wastes not yet generated, the main difference between the baseline cost estimates underpinning the ARO and those underpinning the ONFA Reference Plan relates to internally funded nuclear liability expenditures. These expenditures are not funded under, and cannot be drawn from the ONFA, but are included in the ARO cost estimates as they are part of OPG's legal obligation. The expenditures include used fuel management and L&ILW storage costs incurred during the nuclear stations' operating lives. Refer to Ex. L-C2-01-Staff-081 for further information of internally funded expenditures.

At times, there may also be timing differences in the implementation of changes in nuclear station end-of-life date assumptions as between the cost estimates underpinning the ARO and those underpinning the ONFA Reference Plan. These differences can reflect the fact that sufficient high confidence is required to affect a change in the end-of-life assumptions for accounting purposes, while the ONFA Reference Plan is based on forward-looking planning assumptions and therefore may

lead the ARO in implementing any revisions to the end-of-life dates. Conversely, as was the case in EB-2015-0374 and now as of December 31, 2020, accounting end-of-life date assumptions may lead the quinquennial ONFA Reference Plan update process, as the accounting assumptions are assessed annually by OPG's Depreciation Review Committee. Such a situation would be covered by the existing accounting order application requirements (and proposed Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account) for OPG related to revenue requirement impacts arising from accounting end-of-life changes.

Board Staff Interrogatory #78

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 8

Question(s):

a) Please provide the most recent AFS for the segregated funds.

Response

The Decommissioning Segregated Fund Audited Financial Statements as at December 31, 2020 are provided as Attachment 1. The Used Fuel Segregated Fund Audited Financial Statements as at December 31, 2020 are provided as Attachment 2.

DECOMMISSIONING SEGREGATED FUND

AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2020

Independent auditor's report

To the Audit and Risk Committee of Ontario Power Generation Inc.
and to the Audit and Risk Management Committee of the Ontario Financing Authority

Opinion

We have audited the financial statements of the **Decommissioning Segregated Fund** [the "Fund"], which comprise the statement of net assets as at December 31, 2020, and the statement of operations and comprehensive income, statement of changes in net assets, and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects the financial position of the Fund as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with United States generally accepted accounting principles.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Fund in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Fund's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Fund or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Fund's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Fund's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Funds' ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Fund to cease to continue as a going concern.
- Evaluate the overall presentation, structure, and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Ontario
March 9, 2021

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C2-01-Staff-078
Attachment 1
Page 4 of 22

STATEMENTS OF NET ASSETS

As at December 31 *(millions of dollars)*	2020	2019
Assets		
Investments, at fair value *(Notes 3 and 6)*		
Cash and cash equivalents	**140**	92
Short-term investments	**18**	18
Fixed income investments	**2,879**	2,704
Marketable equity securities	**4,982**	4,471
Pooled funds	**1,417**	1,236
Real assets	**1,735**	1,719
	11,171	10,240
Other		
Receivable for investment transactions	**23**	5
Investment income receivable *(Note 9)*	**24**	23
Derivative contracts *(Note 6)*	**1**	1
	48	29
	11,219	10,269
Liabilities		
Accounts payable and accrued liabilities *(Note 4)*	**13**	13
Payable for investment transactions	**19**	9
	32	22
Net assets	**11,187**	10,247

Commitments *(Note 10)*

See accompanying notes to the financial statements

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C2-01-Staff-078
Attachment 1
Page 5 of 22

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Investment income *(Note 5)*		
Interest	**108**	110
Dividends	**109**	115
Security lending income	**1**	1
	218	226
Expenses		
Investment management and administration fees *(Note 8)*	**44**	37
Net investment income	**174**	189
Other income		
Net realized gains *(Note 5)*	**334**	250
Net unrealized gains *(Note 5)*	**463**	804
Net income and comprehensive income	**971**	1,243

See accompanying notes to the financial statements

STATEMENTS OF CHANGES IN NET ASSETS

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Net assets, beginning of year	**10,247**	9,028
Net income and comprehensive income	**971**	1,243
Eligible nuclear costs *(Note 7)*	**(31)**	(24)
Net assets, end of year	**11,187**	10,247

See accompanying notes to the financial statements

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C2-01-Staff-078
Attachment 1
Page 7 of 22

STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Operating activities		
Interest received	**106**	111
Dividends received	**110**	115
Proceeds received from real assets	**411**	134
Security lending income	**1**	1
Investment management and administration fees paid	**(21)**	(18)
Net realized gains on investments	**193**	227
Proceeds from investments sold in prior year	**5**	3
Payments for investments purchased in prior year	**(9)**	(8)
Purchase of investments	**(717)**	(525)
Foreign exchange contracts settlement from prior year	**(1)**	(1)
Disbursements for eligible nuclear costs	**(30)**	(23)
Cash flow provided by operating activities	**48**	16
Cash and cash equivalents, January 1	**92**	76
Cash and cash equivalents, December 31	**140**	92

See accompanying notes to the financial statements

NOTES TO THE FINANCIAL STATEMENTS

1. DESCRIPTION OF DECOMMISSIONING SEGREGATED FUND

The Ontario Nuclear Funds Agreement (ONFA), as amended, is an agreement between the Province of Ontario (the Province), Ontario Power Generation Inc. (OPG), and various subsidiaries of OPG that became effective in July 2003. The ONFA outlines the roles and responsibilities of the Province and OPG concerning the establishment of the following investment funds in segregated custodial accounts:

- The Decommissioning Segregated Fund (the Fund) to cover eligible costs for the nuclear fixed asset removal and long-term low and intermediate level nuclear waste management; and
- The Used Fuel Segregated Fund to cover eligible costs for the long-term nuclear used fuel waste management.

On July 24, 2003, the ONFA became effective upon the appointment of external investment managers to manage the assets of these funds. CIBC Mellon Global Securities Services Company is an independent custodian of the Fund's assets under the custody agreement dated October 5, 2010.

OPG is the owner of the Fund. Pursuant to the ONFA, each of the Province and the Ontario Electricity Financial Corporation (OEFC), an agency of the Province, has a security interest in the assets of the Fund.

OPG and the Ontario Financing Authority (OFA), an agency of the Province which has been delegated authority to manage the Fund, jointly make decisions on the Fund's asset mix and investment manager selection and retention. The Statement of Investment Policy for the Fund is approved by OPG and the Province. There is a risk that OPG and the OFA may have differing priorities respecting these matters that could impact asset mix and investment decisions.

The Fund is funded in accordance with the ONFA using the reference plans and associated cost estimates that have been prepared by OPG and approved by the Province and may be adjusted from time to time in accordance with the ONFA.

The target rate of return for the Fund based on the discount rate established by the ONFA is as set out in the current approved reference plan. In December 2016, the Province approved a new ONFA reference plan with an effective date of January 1, 2017 (2017 ONFA Reference Plan) to replace the reference plan previously in effect. The 2017 Reference Plan covers the 2017–2021 period. Based on the 2017 ONFA Reference Plan, the target rate of return for the Fund is at 5.15 percent per annum (annual return of 3.25 percent plus an annual inflation component of 1.90 percent), after expenses. The target rate of return for the Fund is unchanged from the previous approved reference plan. For the year ended December 31, 2020, the actual rate of return of the Fund was a gain of 9.5 percent (2019 − 13.8 percent), after expenses.

OPG has not made contributions to the Fund, which has been fully funded at its inception through the initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. No overall contributions are required to be made to the Fund based on the 2017 ONFA Reference Plan.

OPG bears the risk and liability for funding liability increases and fund earnings.

If the actual rate of return of the Fund deviates from the target rate of return, or if there is a change in the value of the funding liabilities as a result of the approval of a new ONFA reference plan, the Fund may become underfunded in the future. Contributions may be required in the future should the Fund be in an underfunded position when a new reference plan is prepared. Variability in asset performance due to volatility inherent in financial markets may result in the Fund becoming underfunded in the future. Changes in cost estimates and planning assumptions used to establish the funding obligation in a future approved ONFA reference plan may also affect the funded status of the Fund at that time.

Amounts are disbursed from the Fund solely for reimbursement of eligible costs associated with nuclear fixed asset removal and long-term low and intermediate level waste management.

If there is a surplus in the Fund such that the liabilities are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Upon termination of the ONFA, the Province has the sole right to any excess funds, which is the extent to which the fair value of the Fund exceeds the estimated completion costs under the current approved reference plan.

As part of OPG's licensing requirements for financial guarantees under the *Nuclear Safety and Control Act* (Canada) in respect of its nuclear generating station decommissioning and nuclear waste management obligations, the Province, OPG and the Canadian Nuclear Safety Commission (CNSC) have entered into an agreement that gives the CNSC access to the assets of the Fund under certain conditions.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Fund represents the assets maintained by OPG in segregated custodial accounts pursuant to the ONFA and does not have a separate legal status. The Fund's financial statements have been prepared by management in accordance with United States generally accepted accounting principles (US GAAP), which is consistent with Section 9.4 of the ONFA.

The Fund meets the definition of an investment company under the revised Accounting Standards Codification Topic 946, *Investment Companies*, which requires all investments to be recorded at fair value.

Given that OPG is the owner of the Fund and the Province owns all of the shares of OPG, related parties include OPG, the Province, and the OEFC.

Certain of the 2019 comparative amounts have been reclassified from financial statements previously presented to conform to the 2020 financial statement presentation. Unless otherwise indicated, all dollar amounts are expressed in millions of Canadian dollars.

Use of Management Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses, and the disclosure of commitments. The valuation of investments is the most significant component of the financial statements subject to estimates. Actual results could differ from these estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market value. Interest earned on cash and cash equivalents and short-term investments is recognized as interest income.

Valuation of Investments

Financial assets and financial liabilities are measured at fair value with gains and losses recognized in income. Financial assets purchased and sold, where the contract requires the asset to be delivered within an established time frame, are recognized on a trade-date basis. All derivatives are recorded at fair value in the statements of net assets. Transaction costs for financial instruments are expensed as incurred.

Fair value is defined as the amount at which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's-length transaction. Where a quoted bid price in an active market is available, the fair value is based on the quoted bid price at the end of the reporting period. In the absence of a quoted price in an active market, the Fund determines fair value using valuation techniques that make maximum use of observable market inputs.

Investments are presented in the financial statements at fair value, with the differences between fair value and average cost recorded as unrealized gains or losses in the Fund's statements of operations and comprehensive income.

The carrying value of cash and cash equivalents and short-term investments approximates their fair value due to their immediate or short-term maturity.

The market values of foreign investments are translated into Canadian dollars at the exchange rates prevailing at the close of each business day. Purchases and sales of foreign securities and income and expenses are translated into Canadian dollars at the exchange rates prevailing on the transaction dates. Gains and losses arising from foreign exchange transactions are recorded in the statements of operations and comprehensive income.

Securities traded on a national securities exchange are valued at the bid price on the last business day of the year. Listed securities for which no trades are recorded on the last business day of the year are valued at the last reported traded price on the last business day on which the security was traded. Pooled funds are valued based on the unit values of the funds as reported by the investment manager and are presented as a separate category on the statements of net assets. Management fees for the pooled funds are expensed as incurred. Securities transactions are recorded on the trade date. Dividends are accrued as of the ex-dividend date. Stock dividends are recorded in income based on the market value of the security. Realized gains or losses on the sale of securities are calculated with reference to the average cost of the securities and included in net realized gains or losses in the statements of operations and comprehensive income. The Fund follows the accrual method of recording investment income.

Real assets consist of infrastructure, real estate, and agriculture investments that are valued based on estimated fair values from financial information as provided by the general partners of the limited partnership funds in which the Fund is invested, or other acceptable industry valuation methods. Management fees for the real assets are expensed as incurred.

For other investments that do not have an established fair value, the fair value is estimated based on comparable securities of issuers with similar credit ratings or net realizable value using available information.

Forward Foreign Exchange Contracts

The Fund may enter into forward foreign exchange contracts for risk management purposes where such activity is consistent with its investment objectives.

The year-end value of forward foreign exchange contracts have been included on the statements of net assets, with the net unrealized gain or loss included in the statements of operations and comprehensive income. The gain or loss arising from the difference between the value of the original forward foreign exchange contract and the contract at close or delivery is realized and recorded in net realized gains or losses in the statements of operations and comprehensive income.

Taxation

Any investment income earned by the Fund is exempt from tax under the *Income Tax Act* (Canada) since the Fund is owned by a tax-exempt entity, namely OPG, and income earned by the Fund is attributed for tax purposes to OPG.

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

Investment income earned in the Fund is exempt from payments in lieu of corporate income taxes based on O. Reg. 207/99 made under the *Electricity Act, 1998*. Accordingly, the Fund has made no provision for income taxes in these financial statements.

DECOMMISSIONING SEGREGATED FUND
For the years ended December 31, 2020 and 2019
(Expressed in millions of $)

3. INVESTMENTS

The fair values and historical costs of the investments as at December 31, 2020 and 2019 are summarized as follows:

	2020		2019	
	Fair Value	Historical Cost	Fair Value	Historical Cost
Cash and cash equivalents	**140**	**140**	92	92
Short-term investments	**18**	**18**	18	18
Fixed income investments				
Domestic	**2,721**	**2,380**	2,570	2,356
United States	**133**	**118**	100	95
Other	**25**	**22**	34	32
	2,879	**2,520**	2,704	2,483
Equities				
Domestic	**1,563**	**1,286**	1,575	1,290
United States	**1,706**	**1,099**	1,448	986
Japan	**309**	**228**	256	199
United Kingdom	**258**	**214**	265	199
Switzerland	**167**	**113**	130	85
Other [1]	**972**	**689**	795	609
	4,975	**3,629**	4,469	3,368
Preferred	**7**	**7**	2	2
Marketable equity securities	**4,982**	**3,636**	4,471	3,370
Pooled funds				
Equities	**464**	**295**	404	296
Fixed income investments	**934**	**878**	813	793
Short-term investments	**19**	**19**	19	19
	1,417	**1,192**	1,236	1,108
Real assets				
Infrastructure	**995**	**595**	1,026	609
Real estate	**669**	**564**	620	515
Agriculture	**71**	**72**	73	72
	1,735	**1,231**	1,719	1,196
Total investments	**11,171**	**8,737**	10,240	8,267

[1] Includes equities from over 40 geographical locations.

DECOMMISSIONING SEGREGATED FUND
For the years ended December 31, 2020 and 2019
(Expressed in millions of $)

A summary of the fair value of domestic fixed income investments, domestic equities and United States (US) equities by industry sector as at December 31, 2020 and 2019 is as follows:

	2020	2019
Domestic fixed income investments		
Government	**1,887**	1,861
Financial	**374**	328
Utilities	**107**	89
Real estate	**76**	63
Energy	**58**	37
Other	**219**	192
	2,721	2,570
Domestic equities		
Financial	**320**	380
Materials	**246**	176
Energy	**190**	266
Technology	**123**	95
Insurance	**117**	122
Media and telecommunications	**99**	84
Transportation	**77**	108
Commercial services	**60**	42
Real estate	**56**	47
Other	**275**	255
	1,563	1,575
US equities		
Technology	**571**	393
Financial	**154**	126
Healthcare	**149**	117
Media and telecommunications	**103**	113
Retail	**97**	76
Pharmaceuticals	**95**	88
Energy	**60**	76
Commercial services	**55**	56
Insurance	**46**	58
Other	**376**	345
	1,706	1,448

The proportion of each category of investments as a percentage of net assets as at December 31, 2020 and 2019 is as follows:

	2020		2019	
	Fair Value	% of Net Assets	Fair Value	% of Net Assets
Cash and cash equivalents	**140**	**1%**	92	1%
Short-term investments	**18**	**0%**	18	0%
Fixed income investments	**2,879**	**26%**	2,704	26%
Marketable equity securities	**4,982**	**44%**	4,471	44%
Pooled funds	**1,417**	**13%**	1,236	12%
Real assets	**1,735**	**16%**	1,719	17%
Total investments	**11,171**	**100%**	10,240	100%
Net assets	**11,187**		10,247	

Issuers representing aggregated investments of greater than 5 percent of net assets as at December 31, 2020 and 2019 are as follows:

	2020		2019	
	Principal Amount	Fair Value	Principal Amount	Fair Value
Fixed income funds [1]	**n/a**	**934**	n/a	813
Province of Ontario	**564**	**729**	543	648
		1,663		1,461

n/a – not applicable
[1] The fixed income funds represent a total of 86,434,652 units (2019 – 78,525,275 units) in three separate funds of the same issuer.

4. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following as at December 31, 2020 and 2019:

	2020	2019
Eligible nuclear costs	**7**	6
Investment management and administration fees	**6**	7
	13	13

5. INVESTMENT INCOME, NET REALIZED GAINS AND NET UNREALIZED GAINS

Investment income, net realized gains, and net unrealized gains for the years ended December 31, 2020 and 2019 consist of the following:

	2020	2019
Investment income		
Interest on cash, short-term investments, and fixed income	**108**	110
Dividends [1]	**109**	115
Security lending income	**1**	1
	218	226
Net realized gains		
Realized gains	**309**	233
Realized foreign exchange gains	**25**	17
	334	250
Net unrealized gains		
Unrealized gains [2]	**414**	996
Unrealized foreign exchange gains (losses)	**49**	(192)
	463	804

[1] Net of withholding taxes of $4 million for 2020 and 2019.
[2] Unrealized gains for real assets are based on the fair values of the assets held, net of cash distributions from the underlying investments. The total cash distributions received were $411 million (2019 - $134 million), comprised of income distributions of $202 million (2019 - $64 million) and return of capital distributions of $209 million (2019 - $70 million).

6. FINANCIAL INSTRUMENTS

The primary objective of the Fund is to meet the payment obligations associated with OPG's nuclear generating station decommissioning and low and intermediate level waste disposal activities as contemplated under the ONFA. In order to meet this objective, the Fund invests in a diversified portfolio of investments comprising primarily equity and fixed income securities.

A Statement of Investment Policies and Procedures (SIPP) for the Fund sets out the investment framework of the Fund, including the investment assumptions, permitted investments and various investment constraints. The SIPP also establishes the long-term target asset mix of the Fund, which considers the Fund's funded status and investment objectives in relation to the projected profile of the underlying long-term liability and cash flows, historical experience of investment vehicles, the appropriate level of diversification to optimize risk and return, and the risk preferences of OPG and the Province. The Fund is invested in equities, fixed income, and real assets. It is primarily assumed that certain equity and other types of investments are expected to provide higher long-term returns than fixed income with a correspondingly higher level of short-term volatility, and that exposure to real assets will improve portfolio diversification, provide the potential for enhanced long-term returns, and reduce portfolio volatility. The management of OPG and the OFA, on behalf of the Province, monitor investment compliance with the SIPP on a quarterly basis.

The SIPP is reviewed and approved annually by the Audit and Risk Committee of OPG's Board of Directors and by the Deputy Minister of Finance, on behalf of the Province.

Risks Associated with Financial Instruments

Credit Risk

Credit risk is the risk that the counterparty to a financial instrument might fail to meet its obligation under the terms of a financial instrument, thereby resulting in a financial loss for the other party to the transaction. The Fund is primarily exposed to credit risk through its fixed income allocation, which is largely invested in Canadian federal, provincial and corporate debt. Credit risk is governed by the SIPP, which requires fixed income to comply with various investment constraints that ensure prudent diversification and minimum credit rating quality. To manage credit risk, compliance with the SIPP is monitored quarterly by an external third-party vendor and reported to the management of OPG and the OFA on a quarterly basis.

The table below summarizes the Fund's exposure to debt instruments with the following credit ratings as at December 31, 2020 and 2019:

Rating	2020	2019
AAA	**16.1%**	24.7%
AA	**51.4%**	47.8%
A	**13.8%**	11.6%
BBB	**12.8%**	11.3%
Less than BBB or not rated	**5.9%**	4.6%
	100.0%	100.0%

Credit ratings are obtained from S&P Global Ratings, Moody's Investment Service, Fitch Ratings and/or the Dominion Bond Rating Services. In the case where more than one rating is obtained for a security, the average rating has been used.

Liquidity Risk

Liquidity risk is the risk that the Fund is unable to meet its financial obligations as they become due. The Fund's approach to managing liquidity risk is to ensure that the Fund has sufficient liquidity to meet its financial obligations when due without incurring unacceptable losses. Liquidity risk of the fund is managed at the overall fund level by considering the expected liquidity of each asset class during the development of the Fund's asset mix and diversifying investments across different asset class types.

Market Risk

Market risk is defined as the risk that an investment's value decreases due to changes in underlying market factors including, but not limited to, concentration risk, currency risk, interest rate risk, and equity price risk.

Market risk of the Fund is managed through the Fund's diversified asset mix, which, in accordance with the SIPP, is expected to be reviewed at least every five years. The review generally coincides with the preparation and approval of reference plans under the ONFA. The target asset mix of the Fund, including tolerance ranges around the target allocation to various asset classes, is governed by the SIPP. Compliance with the target asset mix range is monitored internally on a monthly basis and by an external third-party vendor on a quarterly basis, and reported quarterly to the management of OPG and the OFA.

Concentration Risk

Concentration risk is the risk of investment loss due to lack of diversification in the portfolio. The Fund's exposure to concentration risk is governed by the SIPP. For equities, no holding shall represent more than 10 percent of the total market value of each investment manager's equity portfolio. For fixed income, no more than 10 percent of each investment manager's portfolio may be invested in the bonds of a single issuer and its related companies, except for Canadian federal and provincial bonds and bonds of their agencies. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported to the management of OPG and the OFA.

Currency Risk

Currency risk is the risk that the value of a financial instrument decreases due to changes in foreign exchange rates. The Fund is exposed to currency risk primarily through its foreign equity investment, which is governed through the target asset mix as approved annually in the SIPP. Investment compliance with the target asset mix of the Fund is monitored monthly internally and quarterly by an external third-party vendor, and reported quarterly to the management of OPG and the OFA.

The table below summarizes the major foreign currencies (in Canadian dollars) to which the Fund was exposed to as at December 31, 2020 and 2019, adjusting for forward foreign exchange contracts, if applicable. The table also illustrates the impact of a one percent change in the value of the Canadian dollar relative to each foreign currency shown on the net assets of the Fund, with all other variables held constant.

Currency	Market Value of Investments 2020	Foreign Exchange Contracts Payable 2020	Net Currency Exposure 2020	Net Currency Exposure 2019	Impact of a One Percent Change 2020	Impact of a One Percent Change 2019
US Dollar	**3,299**	**(101)**	**3,198**	2,832	**32**	28
Euro	**787**	**-**	**787**	784	**8**	8
British Pounds	**350**	**-**	**350**	337	**4**	3
Japanese Yen	**320**	**-**	**320**	259	**3**	3
Swiss Franc	**157**	**-**	**157**	123	**2**	1

Actual results may differ materially from this sensitivity analysis.

Interest Rate Risk

Interest rate risk, which includes credit spread risk, is the risk of investment loss due to changes in interest rates and changes in the market price of credit. The Fund is exposed to interest rate risk through its target asset mix, which includes an allocation to fixed income securities. Cash and cash equivalents and short-term investments with maturity dates of less than one year from the financial statement date have minimal exposure to interest rate fluctuations. The Fund's exposure to interest rate risk is governed by the SIPP, which ensures that the Fund's fixed income exposure is prudently diversified. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported quarterly to the management of OPG and the OFA.

The table below provides a summary of the Fund's fixed income by maturity as at December 31, 2020 and 2019:

	2020	2019
Fixed income		
1 to 5 years	**515**	577
5 to 10 years	**432**	392
Over 10 years	**1,932**	1,735
	2,879	2,704
Average yield	**1.51%**	2.27%

Effective duration is a measure of the sensitivity of the price of a fixed income instrument to a change in interest rates. Using the Fund's effective duration of 11.6 years as at December 31, 2020 (2019 – 11.5 years), a parallel shift in the yield curve of +/- 0.5 percent would result in a $167 million impact (2019 − $155 million) on the net assets of the Fund, with all other variables held constant. Actual results may differ materially from this sensitivity analysis.

Equity Price Risk

Equity price risk is the risk of loss due to a decline in equity prices. The Fund is exposed to equity price risk through its target asset mix, which includes an allocation to equity securities. The Fund's exposure to equity risk is governed by the SIPP, which ensures that the Fund's equity exposure is prudently diversified. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported quarterly to the management of OPG and the OFA.

The table below approximates the potential dollar impact on the net assets of the Fund associated with a one percent change in each of the specified equity indices as at December 31. This analysis is based on the market values of the Fund's equity holdings at the end of the specified periods, as well as on the assumption that when one equity index changes by one percent, all other variables are held constant.

		2020	2019
Asset Class	**Equity Index**		
Domestic equity	S&P/TSX	**16**	16
US equity	S&P 500	**17**	14
Other equity	MSCI EAFE	**17**	14

Actual results may differ materially from this sensitivity analysis.

Derivatives

The Fund enters into derivative contracts, such as forward foreign exchange contracts, for risk management purposes where such activity is consistent with its investment objectives. Forward contracts expose the Fund to counterparty credit risk should the Fund's counterparty to any such transaction default on its contractual obligations. Since the fair value of the forward foreign exchange contracts outstanding as at December 31, 2020 represents less than one percent of the Fund's net assets, the counterparty credit risk exposures on such transactions have a minimal impact on the Fund.

	2020	2019
Forward foreign exchange contracts		
Receivable	**102**	42
Payable	**(101)**	(41)
	1	**1**

The Fund may also enter into derivative contracts, such as futures contracts, to replicate direct investments in underlying securities. As at December 31, 2020, the Fund held equity futures contracts with a market value of nil (2019 − nil). In accordance with the Fund's SIPP, 100 percent of these investments are secured by cash and short-term investments.

Securities Lending

The Fund is exposed to counterparty credit risk associated with its security lending activities. The risk is mitigated by the use of non-cash collateral and through a borrower default protection that is jointly and severally provided to OPG by the Fund's custodian and its related entities. The Fund requires the borrower to pledge and to deliver collateral as security for each loan at no less than 105 percent of the market value of the securities loaned for Canadian securities, 102 percent of the market value of the securities loaned for US securities and the percentage that reflects best practices in other local markets in which other foreign currency securities are loaned.

The following table provides a summary of the Fund's securities on loan and collateral held as at December 31, 2020 and 2019:

	2020	2019
Securities on loan		
Marketable equity securities	**274**	294
Fixed income	**244**	446
	518	740
Collateral held	**585**	782
Collateral percentage	**112.9%**	105.7%

Additional Information on Fair Value

Financial assets are measured at fair value in accordance with the fair value hierarchy. This hierarchy groups financial assets and financial liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The level within which the financial asset or financial liability is classified is determined based on the lowest level input that is significant to the fair value measurement.

The fair value of pooled funds is reported on the basis of NAV and is classified as Level 2. Real assets are measured at fair value by their investment managers using NAV as a practical expedient. Investments measured at NAV as a practical expedient for determining fair value are excluded from the fair value hierarchy.

The following tables provide summaries of the financial assets measured at fair value in the statements of net assets grouped into the fair value hierarchy as at December 31, 2020 and 2019:

2020	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	**140**	**-**	**-**	**140**
Short-term investments	**-**	**18**	**-**	**18**
Fixed income	**-**	**2,879**	**-**	**2,879**
Marketable equity securities	**4,982**	**-**	**-**	**4,982**
Pooled funds	**-**	**1,417**	**-**	**1,417**
Derivative contracts	**-**	**1**	**-**	**1**
	5,122	**4,315**	**-**	**9,437**
Investments measured at NAV [1]				**1,735**
				11,172

2019	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	92	-	-	92
Short-term investments	-	18	-	18
Fixed income	-	2,704	-	2,704
Marketable equity securities	4,471	-	-	4,471
Pooled funds	-	1,236	-	1,236
Derivative contracts	-	1	-	1
	4,563	3,959	-	8,522
Investments measured at NAV [1]				1,719
				10,241

[1] Investments measured at fair value using NAV as a practical expedient have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented in the statements of net assets.

The tables above exclude receivables and payables.

There were no transfers between Level 1 and Level 2 and into or out of Level 3 during the reporting period.

Certain real estate investments were purchased from entities related to investment managers of the Fund. These entities were related to the investment manager due to common control. The real estate investments were measured at the exchange amount of the consideration paid as established by third-party real estate appraisers. The recorded amount of consideration paid in 2020 was $10 million (2019 – nil) and proceeds received in 2020 were $2 million (2019 – nil).

7. ELIGIBLE NUCLEAR COSTS

The ONFA sets out a process that must be followed prior to any amounts being disbursed from the Fund and gives the Province the right to review and approve all disbursements for eligible costs associated with nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and storage. All disbursements to date have been made to OPG.

Eligible costs from inception to December 31, 2020 were as follows:

	Annual	Inception-to-date
2020	**31**	**623**
2019	24	592
Inception to 2018	n/a	568

n/a – not applicable

8. INVESTMENT MANAGEMENT AND ADMINISTRATION FEES

Investment management and administration fees for the years ended December 31, 2020 and 2019 were as follows:

	2020	2019
Investment management fees	**41**	36
Custodian fees	**1**	1
Other administration fees (audit, consulting, and legal)	**2**	-
	44	37

For the year ended December 31, 2020, the ratio of expenses over net assets was 0.4 percent (2019 − 0.4 percent).

9. INVESTMENT INCOME RECEIVABLE

The following table summarizes investment income receivables that were outstanding as at December 31, 2020 and 2019:

	2020	2019
Interest receivable	**14**	12
Dividends receivable and other receivables	**10**	11
	24	23

10. COMMITMENTS

The Fund has committed to entering into real asset investments, which may be funded over the next several years in accordance with the agreed-upon terms and conditions. As at December 31, 2020, these commitments totalled $807 million (2019 – $695 million). The investments in real assets are generally not redeemable.

11. COVID-19 PANDEMIC

The outbreak of the disease caused by a novel strain of coronavirus, identified as “COVID-19," since the beginning of the 2020 year has resulted in governments worldwide enacting a range of emergency measures to combat the spread of the virus. These measures, which have included the implementation of lockdowns, travel bans, self-imposed quarantine periods and physical distancing requirements, have caused material disruption to many businesses globally, resulting in an economic slowdown and financial market volatility. Governments and central banks in Canada and the United States have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions and promote economic recovery. The duration and ultimate impact of the COVID-19 pandemic is unknown at this time, as is the ultimate efficacy of the government and central bank interventions. It is not possible to reliably estimate the length and extent of these developments and the impact, if any, on the financial results and condition of the Fund in future periods.

USED FUEL SEGREGATED FUND

AUDITED FINANCIAL STATEMENTS

DECEMBER 31, 2020

Independent auditor's report

To the Audit and Risk Committee of Ontario Power Generation Inc.
and to the Audit and Risk Management Committee of the Ontario Financing Authority

Opinion

We have audited the financial statements of the **Used Fuel Segregated Fund** [the "Fund"], which comprise the statement of net assets as at December 31, 2020, and the statement of operations and comprehensive income, statement of changes in net assets, and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects the financial position of the Fund as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with United States generally accepted accounting principles.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Fund in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Fund's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Fund or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Fund's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Fund's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Fund's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Fund to cease to continue as a going concern.
- Evaluate the overall presentation, structure, and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Ontario
March 9, 2021

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C2-01-Staff-078
Attachment 2
Page 4 of 24

STATEMENTS OF NET ASSETS

As at December 31 *(millions of dollars)*	2020	2019
Assets		
Investments, at fair value *(Notes 4 and 7)*		
Cash and cash equivalents	**175**	119
Short-term investments	**16**	14
Fixed income investments	**3,787**	3,591
Marketable equity securities	**6,456**	5,882
Pooled funds	**1,976**	1,728
Real assets	**2,176**	2,136
	14,586	13,470
Other		
Receivable for investment transactions	**39**	7
Investment income receivable *(Note 11)*	**33**	31
Derivative contracts *(Note 7)*	**1**	1
	73	39
	14,659	13,509
Liabilities		
Accounts payable and accrued liabilities *(Note 5)*	**47**	41
Payable for investment transactions	**34**	12
Payable to Province of Ontario for rate of return adjustment *(Notes 7 and 10)*	**3,583**	2,920
	3,664	2,973
Net assets	**10,995**	10,536

Commitments *(Note 12)*

See accompanying notes to the financial statements

Filed: 2021-04-19
EB-2020-0290
Exhibit L
C2-01-Staff-078
Attachment 2
Page 5 of 24

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Investment income *(Note 6)*		
Interest	**142**	146
Dividends	**143**	152
Security lending income	**1**	1
	286	299
Expenses		
Investment management and administration fees *(Note 9)*	**56**	46
Net investment income	**230**	253
Other income		
Net realized gains *(Note 6)*	**405**	321
Net unrealized gains *(Note 6)*	**599**	1,039
Province of Ontario rate of return adjustment *(Note 10)*	**(663)**	(937)
Net income and comprehensive income	**571**	676

See accompanying notes to the financial statements

STATEMENTS OF CHANGES IN NET ASSETS

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Net assets, beginning of year	**10,536**	9,949
Net income and comprehensive income	**571**	676
Eligible nuclear costs *(Note 8)*	**(112)**	(89)
Net assets, end of year	**10,995**	10,536

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	**2020**	**2019**
Operating activities		
Interest received	**141**	147
Dividends received	**142**	151
Proceeds received from real assets	**506**	167
Security lending income	**1**	1
Investment management and administration fees paid	**(26)**	(23)
Net realized gains on investments	**243**	295
Proceeds from investments sold in prior year	**7**	4
Payments for investments purchased in prior year	**(12)**	(11)
Purchase of investments	**(837)**	(646)
Foreign exchange contracts settlement from prior year	**(1)**	(1)
Disbursements for eligible nuclear costs	**(108)**	(69)
Cash flow provided by operating activities	**56**	15
Net change in cash and cash equivalents	**56**	15
Cash and cash equivalents, January 1	**119**	104
Cash and cash equivalents, December 31	**175**	119

See accompanying notes to the financial statements

NOTES TO THE FINANCIAL STATEMENTS

1. DESCRIPTION OF USED FUEL SEGREGATED FUND

The Ontario Nuclear Funds Agreement (ONFA), as amended, is an agreement between the Province of Ontario (the Province), Ontario Power Generation Inc. (OPG), and various subsidiaries of OPG that became effective in July 2003. The ONFA outlines the roles and responsibilities of the Province and OPG concerning the establishment of the following investment funds in segregated custodial and trust accounts:

- The Used Fuel Segregated Fund (the Fund) to cover eligible costs for the long-term nuclear used fuel waste management; and
- The Decommissioning Segregated Fund to cover eligible costs for the nuclear fixed asset removal and long-term low and intermediate level nuclear waste management.

On July 24, 2003, the ONFA became effective upon the appointment of external investment managers to manage the assets of these funds. CIBC Mellon Global Securities Services Company is an independent custodian of the Fund's assets under the custody agreement dated October 5, 2010.

OPG is the owner of the Fund. The Province, pursuant to the ONFA, has a security interest in the assets of the Fund.

OPG and the Ontario Financing Authority (OFA), an agency of the Province which has been delegated authority to manage the Fund, jointly make decisions on the Fund's asset mix and investment manager selection and retention. The Statement of Investment Policy for the Fund is approved by the Province. There is a risk that OPG and the OFA may have differing priorities respecting these matters that could impact asset mix and investment decisions.

The Fund includes the net assets of The Ontario NFWA Trust (the Trust). The Trust was established by OPG in November 2002 in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). Also in accordance with the NFWA, owners of nuclear fuel waste established, by incorporation, the Nuclear Waste Management Organization (NWMO), whose purpose is to propose to the Government of Canada approaches for the management of nuclear fuel waste and to implement the approach that is selected by the Federal Government. In June 2007, the Government of Canada selected the Adaptive Phased Management approach recommended by the NWMO. The funds in the NFWA Trust will be used to meet the payment obligations associated with the long-term management of used nuclear fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the Trust. The Province, pursuant to the ONFA, has a security interest in OPG's beneficial interest in the Trust. As at December 31, 2020, the net assets in the Trust were $4,988 million (2019 – $4,399 million). The remaining assets in the Fund are held in segregated custodian accounts.

The Fund is funded in accordance with the ONFA using the reference plans and associated cost estimates that have been prepared by OPG and approved by the Province and may be adjusted from time to time in accordance with the ONFA.

In December 2016, the Province approved a new ONFA reference plan with an effective date of January 1, 2017 (2017 ONFA Reference Plan) to replace the 2012 ONFA Reference Plan previously in effect since January 1, 2012. The 2017 ONFA Reference Plan placed the Fund in a fully funded position for the first time since the Fund's inception. As such, no overall contributions to the Fund are required for the 2017–2021 period covered by the 2017 ONFA Reference Plan. Contributions may be required in the future should the Fund be in an underfunded position when a new reference plan is prepared. Variability in asset performance due to volatility inherent in financial markets may result in the Fund becoming underfunded in the future. Changes in cost estimates and planning assumptions used to establish the funding obligation in a future approved ONFA reference plan may also affect the funded status of the Fund at that time.

Under the NFWA, OPG is required to make a contribution to the Trust each year, within 30 days of the submission of the NWMO's Annual Report to the federal Minister of Natural Resources. The contribution amount each year is based on the funding formula approved by the federal Minister of Natural Resources. OPG's contributions to the Fund as well as any portion of the Fund currently not in the Trust can be applied to satisfy the Trust's annual contribution requirements. Refer to Note 3 for details on contributions made to the Trust.

Under the ONFA, the Province guarantees OPG's cumulative return in the Fund at 3.25 percent, plus the rate of change in the Ontario Consumer Price Index (CPI) as defined by the ONFA, compounded annually, for funding related to the first 2.23 million used fuel bundles (Committed Return). The difference between the Committed Return on the Fund and the actual market return based on the fair value of the Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the Committed Return were to be settled as of the statement of net assets date. If the Fund cumulatively earns a market return that is less than the Committed Return, upon approval of a new ONFA reference plan, the Province is obligated to make a corresponding contribution to the Fund.

As prescribed under the ONFA, earnings on OPG's contributions for fuel bundles in excess of the 2.23 million bundle threshold (incremental fuel bundles) are not subject to the Province's guaranteed rate of return and earn a return based on the net realized investment income and changes in the market value of the Fund's assets.

The target rate of return for the Fund is a total annual real return of 3.25 percent, which equals the rate of change in the Ontario CPI plus 3.25 percent compounded annually, after expenses. Refer to Note 10 for information on the Fund's actual rate of return.

The Fund's net assets of $10,995 million (2019 - $10,536 million) as at December 31, 2020 consist of $8,063 million (2019 – $8,050 million) for the cumulative funding contributions, including the compounded Committed Return, related to the first 2.23 million used fuel bundles, and $2,932 million (2019 – $2,486 million) attributed to OPG's funding liability associated with the incremental fuel bundles.

Amounts are disbursed from the Fund solely for reimbursement of eligible costs associated with long-term nuclear used fuel waste management.

The Province is entitled, at any time prior to the termination of the Fund, to any surplus in the Fund subject to a threshold over-funded ratio of 110 percent. Upon termination of the Fund, the Province has the sole right to any surplus above the 100 percent funded threshold in the Fund. Funds may not be directed from the Fund to the Decommissioning Segregated Fund.

As part of OPG's licensing requirements for financial guarantees under the *Nuclear Safety and Control Act* (Canada) in respect of OPG's nuclear station decommissioning and nuclear waste management obligations, the Province, OPG and the Canadian Nuclear Safety Commission (CNSC) have entered into an agreement that gives the CNSC access, under certain conditions, to the assets of the Fund, excluding the Trust.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Fund represents the assets maintained by OPG in segregated custodial accounts pursuant to the ONFA and does not have a separate legal status. The Fund's financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP), which is consistent with Section 9.4 of the ONFA.

The Fund meets the definition of an investment company under the revised Accounting Standards Codification Topic 946, *Investment Companies*, which requires all investments to be recorded at fair value.

Given that OPG is the owner of the Fund and the Province owns all of the shares of OPG, related parties include OPG and the Province.

Certain of the 2019 comparative amounts have been reclassified from financial statements previously presented to conform to the 2020 financial statement presentation. Unless otherwise indicated, all dollar amounts are expressed in millions of Canadian dollars.

Use of Management Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses, and the disclosure of contingent assets and liabilities. The valuation of investments is the most significant component of the financial statements subject to estimates. Actual results could differ from these estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market value. Interest earned on cash and cash equivalents and short-term investments is recognized as interest income.

Valuation of Investments

Financial assets and liabilities, including the corresponding payable to the Province, are measured at fair value with gains and losses recognized in income. Financial assets purchased and sold where the contract requires the asset to be delivered within an established time frame are recognized on a trade-date basis. All derivatives are recorded at fair value in the statements of net assets. Transaction costs for financial instruments are expensed as incurred.

Fair value is defined as the amount at which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's-length transaction. Where a quoted bid price in an active market is available, the fair value is based on the quoted bid price at the end of the reporting period. In the absence of a quoted price in an active market, the Fund determines fair value using valuation techniques that make maximum use of observable market inputs.

Investments are presented in the financial statements at fair value, with the differences between fair value and average cost recorded as unrealized gains or losses in the Fund's statements of operations and comprehensive income.

The carrying value of cash and cash equivalents and short-term investments approximates their fair value due to their immediate or short-term maturity.

The market values of foreign investments are translated into Canadian dollars at the exchange rates prevailing at the close of each business day. Purchases and sales of foreign securities and income and expenses are translated into Canadian dollars at the exchange rates prevailing on the transaction dates. The gains and losses arising from foreign exchange transactions are recorded in the statements of operations and comprehensive income.

Securities traded on a national securities exchange are valued at the bid price on the last business day of the year. Listed securities for which no trades are recorded on the last business day of the year are valued at the last reported traded price on the last business day on which the security was traded. Pooled funds are valued based on the unit value of the pooled fund as reported by the investment manager and are presented as a separate category on the statements of net assets. Management fees for the pooled funds are expensed as incurred. Securities transactions are recorded on the trade date. Dividends are accrued as of the ex-dividend date. Stock dividends are recorded in income based on the market value of the security. The realized gains or losses on the sale of securities are calculated with reference to the average cost of the securities and included in net realized gains or losses in the statements of operations and comprehensive income. The Fund follows the accrual method of recording investment income.

Real assets consist of infrastructure, real estate, and agriculture investments that are valued based on estimated fair values from financial information as provided by the general partners of the limited partnership funds in which the Fund is invested, or other acceptable industry valuation methods. Management fees for the real assets are expensed as incurred.

For other investments that do not have an established fair value, the fair value is estimated based on comparable securities of issuers with similar credit ratings or net realizable value using available information.

Forward Foreign Exchange Contracts

The Fund may enter into forward foreign exchange contracts for risk management purposes where such activity is consistent with its investment objectives.

The year-end value of forward foreign exchange contracts have been included in the investments on the statements of net assets with the net unrealized gain or loss included in the statements of operations and comprehensive income. The gain or loss arising from the difference between the value of the original forward foreign exchange contract and the contract at close or delivery is realized and recorded in net realized gains or losses in the statements of operations and comprehensive income.

Taxation

Any investment income earned by the Fund is exempt from tax under the *Income Tax Act* (Canada) since the Fund is owned by a tax-exempt entity, namely OPG, and income earned by the Fund is attributed for tax purposes to OPG. Any income earned by the Trust is also exempt from tax under the *Income Tax Act* (Canada).

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

Investment income earned in the Fund is exempt from payments in lieu of corporate income taxes based on O. Reg. 207/99 made under the *Electricity Act, 1998*.

Accordingly, the Fund has made no provision for income taxes in these financial statements.

3. CONTRIBUTIONS

The Fund is funded by OPG in accordance with the ONFA based on the applicable reference plan, as approved by the Province and as may be adjusted from time to time in accordance with the ONFA. In 2020, OPG contributions were nil (2019 – nil) to the Fund. The annual contribution to the Trust was $64 million (2019 – $67 million), which was transferred from the non-Trust portion of the Fund. The table below summarizes OPG's inception-to-date contributions to the Fund.

Contributions to Used Fuel Segregated Fund	Annual	Inception-to-date
2020	**-**	**5,812**
2019	-	5,812
Inception to 2018	n/a	5,812

USED FUEL SEGREGATED FUND
For the years ended December 31, 2020 and 2019
(Expressed in millions of $)

4. INVESTMENTS

The fair values and historical costs of the investments as at December 31, 2020 and 2019 are summarized as follows:

	2020		2019	
	Fair Value	Historical Cost	Fair Value	Historical Cost
Cash and cash equivalents	**175**	**175**	119	121
Short-term investments	**16**	**16**	14	14
Fixed income investments				
Domestic	**3,572**	**3,257**	3,407	3,254
United States	**176**	**157**	136	130
Other	**39**	**36**	48	46
	3,787	**3,450**	3,591	3,430
Equities				
Domestic	**2,047**	**1,658**	2,081	1,690
United States	**2,196**	**1,410**	1,918	1,306
Japan	**401**	**296**	333	258
United Kingdom	**336**	**284**	347	266
Switzerland	**215**	**149**	173	117
Other [1]	**1,251**	**903**	1,027	796
	6,446	**4,700**	5,879	4,433
Preferred	**10**	**9**	3	2
Marketable equity securities	**6,456**	**4,709**	5,882	4,435
Pooled funds				
Equities	**623**	**380**	543	381
Fixed income investments	**1,327**	**1,256**	1,161	1,142
Short-term investments	**26**	**26**	24	24
	1,976	**1,662**	1,728	1,547
Real assets				
Infrastructure	**1,262**	**762**	1,285	778
Real estate	**827**	**697**	761	632
Agriculture	**87**	**88**	90	87
	2,176	**1,547**	2,136	1,497
Total investments	**14,586**	**11,559**	13,470	11,044

[1] Includes equities from over 40 geographical locations.

USED FUEL SEGREGATED FUND
For the years ended December 31, 2020 and 2019
(Expressed in millions of $)

A summary of the fair value of domestic fixed income investments, domestic equities and United States (US) equities by industry sector as at December 31, 2020 and 2019 is as follows:

	2020	2019
Domestic fixed income		
Government	**2,193**	2,208
Financial	**627**	570
Utilities	**184**	158
Real estate	**133**	105
Energy	**89**	64
Other	**346**	302
	3,572	3,407
Domestic equities		
Financial	**423**	507
Materials	**323**	232
Energy	**250**	354
Technology	**159**	125
Insurance	**152**	161
Media and telecommunications	**126**	111
Transportation	**99**	138
Commercial services	**78**	54
Automobiles and components	**77**	49
Other	**360**	350
	2,047	2,081
US equities		
Technology	**737**	519
Financial	**197**	170
Healthcare	**188**	151
Media and telecommunications	**133**	147
Retail	**126**	99
Pharmaceuticals	**121**	117
Energy	**78**	101
Commercial services	**69**	78
Insurance	**59**	80
Other	**488**	456
	2,196	1,918

The proportion of each category of investments as a percentage of net assets as at December 31, 2020 and 2019 is as follows:

	2020		2019	
	Fair Value	% of Net Assets	Fair Value	% of Net Assets
Cash and cash equivalents	**175**	**2%**	119	1%
Short-term investments	**16**	**0%**	14	0%
Fixed income investments	**3,787**	**34%**	3,591	34%
Marketable equity securities	**6,456**	**59%**	5,882	56%
Pooled funds	**1,976**	**18%**	1,728	17%
Real assets	**2,176**	**20%**	2,136	20%
Total investments	**14,586**	**133%**	13,470	128%
Net assets	**10,995**		10,536	

Issuers representing aggregated investments of greater than 5 percent of net assets as at December 31, 2020 and 2019 are as follows:

	2020		2019	
	Principal Amount	Fair Value	Principal Amount	Fair Value
Fixed income funds [1]	**n/a**	**1,327**	n/a	1,161
Province of Ontario	**699**	**881**	664	789
		2,208		1,950

n/a – not applicable

[1] The fixed income funds represent a total of 124,217,583 units (2019 – 113,389,542 units) in three separate funds of the same issuer.

5. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following as at December 31, 2020 and 2019:

	2020	2019
Eligible nuclear costs	**38**	34
Investment management and administration fees	**9**	7
	47	41

6. INVESTMENT INCOME, NET REALIZED GAINS, AND NET UNREALIZED GAINS

Investment income, net realized gains, and net unrealized gains for the years ended December 31, 2020 and 2019 consist of the following:

	2020	2019
Investment income		
Interest on cash, short-term investments, and fixed income	**142**	146
Dividends [1]	**143**	152
Security lending income	**1**	1
	286	299
Net realized gains		
Realized gains	**363**	297
Realized foreign exchange gains	**42**	24
	405	321
Net unrealized gains		
Unrealized gains [2]	**531**	1,299
Unrealized foreign exchange gains (losses)	**68**	(260)
	599	1,039

[1] Net of withholding taxes of $5 million and $6 million for 2020 and 2019, respectively.
[2] Unrealized gains for real assets are based on the fair values of the assets held, net of cash distributions from the underlying investments. The total cash distributions received were $506 million (2019 - $167 million), comprised of income distributions of $251 million (2019 - $81 million) and return of capital distributions of $255 million (2019 - $86 million).

7. FINANCIAL INSTRUMENTS

The primary objective of the Fund is to meet the payment obligations associated with OPG's long-term nuclear used fuel waste management activities, as contemplated under the ONFA. In order to meet this objective, the Fund invests in a diversified portfolio of investments comprising primarily equity and fixed income securities.

A Statement of Investment Policies and Procedures (SIPP) for the Fund sets out the investment framework of the Fund, including the investment assumptions, permitted investments and various investment constraints. The SIPP also establishes the long-term target asset mix of the Fund, which considers the Fund's funded status and investment objectives in relation to the projected profile of the underlying long-term liability and cash flows, historical experience of investment vehicles, the appropriate level of diversification to optimize risk and return, and the risk preferences of OPG and the Province. The Fund is invested in equities, fixed income, and real assets. It is primarily assumed that certain equity and other types of investments are expected to provide higher long-term returns than fixed income with a correspondingly higher level of short-term volatility, and that exposure to real assets will improve portfolio diversification, provide the potential for enhanced long-term returns, and reduce portfolio volatility. The management of OPG and the OFA, on behalf of the Province, monitor investment compliance with the SIPP on a quarterly basis.

The SIPP is reviewed and approved annually by the Deputy Minister of Finance, on behalf of the Province.

Risks Associated with Financial Instruments

Credit Risk

Credit risk is the risk that the counterparty to a financial instrument may fail to meet its obligation under the terms of a financial instrument, thereby resulting in a financial loss for the other party to the transaction. The Fund is primarily exposed to credit risk through its fixed income allocation, which is largely invested in Canadian federal, provincial and corporate debt. Credit risk is governed by the SIPP, which requires fixed income to comply with various investment constraints that ensure prudent diversification and minimum credit rating quality. To manage credit risk, compliance with the SIPP is monitored quarterly by an external third-party vendor and reported to the management of OPG and the OFA on a quarterly basis.

The table below summarizes the Fund's exposure to debt instruments with the following credit ratings as at December 31, 2020 and 2019:

Rating	2020	2019
AAA	**14.0%**	22.9%
AA	**45.9%**	42.7%
A	**17.3%**	14.6%
BBB	**15.8%**	14.6%
Less than BBB or not rated	**7.0%**	5.2%
	100.0%	100.0%

Credit ratings are obtained from S&P Global Ratings, Moody's Investment Service, Fitch Ratings and/or the Dominion Bond Rating Services. In the case where more than one rating is obtained for a security, the average rating has been used.

Liquidity Risk

Liquidity risk is the risk that the Fund is unable to meet its financial obligations due at any point in time. The Fund's approach to managing liquidity risk is to ensure that the Fund has sufficient liquidity to meet its financial obligations when due without incurring unacceptable losses. Liquidity risk of the Fund is managed at the overall fund level by considering the expected liquidity of each asset class during the development of the Fund's asset mix and diversifying investments across different asset class types.

Market Risk

Market risk is defined as the risk that an investment's value decreases due to changes in underlying market factors including, but not limited to, concentration risk, currency risk, interest rate risk, and equity price risk.

Market risk of the Fund is managed through the Fund's diversified asset mix, which, in accordance with the SIPP, is expected to be reviewed at least every five years. The review generally coincides with the preparation and approval of reference plans under the ONFA. The target asset mix of the Fund, including tolerance ranges around the target allocation to various asset classes, is governed by the SIPP. Compliance with the target asset mix range is monitored internally on a monthly basis and by an external third-party vendor on a quarterly basis, and reported quarterly to the management of OPG and the OFA.

Concentration Risk

Concentration risk is the risk of investment loss due to lack of diversification in the portfolio. The Fund's exposure to concentration risk is governed by the SIPP. For equities, no holding shall represent more than 10 percent of the total market value of each investment manager's equity portfolio. For fixed income, no more than 10 percent of each investment manager's portfolio may be invested in the bonds of a single issuer and its related companies, except for Canadian federal and provincial bonds and bonds of their agencies. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported to the management of OPG and the OFA.

Currency Risk

Currency risk is the risk that the value of a financial instrument decreases due to changes in foreign exchange rates. The Fund is exposed to currency risk primarily through its foreign equity investment, which is governed through the target asset mix of the Fund as approved annually in the SIPP. Investment compliance with the target asset mix is monitored monthly internally and quarterly by an external third-party vendor, and reported quarterly to the management of OPG and the OFA.

The table below summarizes the major foreign currencies (in Canadian dollars) to which the Fund was exposed to as at December 31, 2020 and 2019, adjusting for any forward foreign exchange contracts, if applicable. The table also illustrates the impact of a one percent change in the value of the Canadian dollar relative to each foreign currency shown on the net assets of the Fund, with all other variables held constant.

	Market Value of Investments	**Foreign Exchange Contracts Payable**	**Net Currency Exposure**		**Impact of a One Percent Change**	
Currency	**2020**	**2020**	**2020**	**2019**	**2020**	**2019**
US Dollar	**4,247**	**(133)**	**4,114**	3,705	**41**	37
Euro	**1,008**	**-**	**1,008**	984	**10**	10
British Pound	**456**	**-**	**456**	443	**5**	4
Japanese Yen	**416**	**-**	**416**	337	**4**	3
Swiss Franc	**201**	**-**	**201**	164	**2**	2

Actual results may differ materially from this sensitivity analysis.

Interest Rate Risk

Interest rate risk, which includes credit spread risk, is the risk of investment loss due to changes in interest rates and changes in the market price of credit. The Fund is exposed to interest rate risk through its target asset mix, which includes an allocation to fixed income securities. Cash and cash equivalents and short-term investments with maturity dates of less than one year from the financial statement date have minimal exposure to interest rate fluctuations. The Fund's exposure to interest rate risk is governed by the SIPP, which ensures that the Fund's fixed income exposure is prudently diversified. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported quarterly to the management of OPG and the OFA.

The table below provides a summary of the Fund's fixed income by maturity as at December 31, 2020 and 2019:

	2020	2019
Fixed income		
1 to 5 years	**892**	1,029
5 to 10 years	**779**	640
Over 10 years	**2,116**	1,922
	3,787	3,591
Average yield	**1.49%**	2.33%

Effective duration is a measure of the sensitivity of the price of a fixed income instrument to a change in interest rates. Using the Fund's effective duration of 10.4 years as at December 31, 2020 (2019 – 9.8 years), a parallel shift in the yield curve of +/- 0.5 percent would result in a $197 million (2019 − $176 million) impact on the net assets of the Fund, with all other variables held constant. Actual results may differ materially from this sensitivity analysis.

Equity Price Risk

Equity price risk is the risk of loss due to a decline in equity prices. The Fund is exposed to equity price risk through its target asset mix, which includes an allocation to equity securities. The Fund's exposure to equity risk is governed by the SIPP, which ensures that the Fund's equity exposure is prudently diversified. Investment compliance with the SIPP is monitored quarterly by an external third-party vendor and reported quarterly to the management of OPG and the OFA.

The table below approximates the potential dollar impact on the Fund's net income and comprehensive income associated with a one percent change in each of the specified equity indices as at December 31. This analysis is based on the market values of the Fund's equity holdings at the end of the specified periods, as well as on the assumption that when one equity index changes by one percent, all other variables are held constant.

		2020	2019
Asset Class	**Equity Index**		
Domestic equity	S&P/TSX	**20**	21
US equity	S&P 500	**22**	19
Other equity	MSCI EAFE	**22**	19

Actual results may differ materially from this sensitivity analysis.

Derivatives

The Fund enters into derivative contracts, such as forward foreign exchange contracts, for risk management purposes where such activity is consistent with its investment objectives. Forward contracts expose the Fund to counterparty credit risk should the Fund's counterparty to any such transaction default on its contractual obligations. Since the fair value of the forward foreign exchange contracts outstanding as at December 31, 2020 represents less than one percent of the Fund's net assets, the counterparty credit risk exposures on such transactions have a minimal impact on the Fund.

	2020	2019
Forward foreign exchange contracts		
Receivable	**134**	55
Payable	**(133)**	(54)
	1	1

The Fund may also enter into derivative contracts, such as futures contracts, to replicate direct investments in underlying securities. As at December 31, 2020, the Fund held equity futures contracts with a market value of nil (2019 – nil). In accordance with the Fund's SIPP, 100 percent of these investments are secured by cash and short-term investments.

Securities Lending

The Fund is exposed to counterparty credit risk associated with its security lending activities. The risk is mitigated by the use of non-cash collateral and through a borrower default protection that is jointly and severally provided to OPG by the Fund's custodian and its related entities. The Fund requires the borrower to pledge and to deliver collateral as security for each loan at no less than 105 percent of the market value of the securities loaned for Canadian securities, 102 percent of the market value of the securities loaned for US securities and the percentage that reflects best practices in other local markets in which other foreign currency securities are loaned.

The following table provides a summary of the Fund's securities on loan and collateral held as at December 31, 2020 and 2019:

	2020	2019
Securities on loan		
Marketable equity securities	**317**	411
Fixed income	**20**	42
	337	453
Collateral held	**400**	480
Collateral percentage	**118.7%**	106.0%

Additional Information on Fair Value

Financial assets are measured at fair value in accordance with the fair value hierarchy. This hierarchy groups financial assets and financial liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The level within which the asset or liability is classified is determined based on the lowest level input that is significant to the fair value measurement.

The fair value of pooled funds is reported on the basis of NAV and is classified as Level 2. Real assets are measured at fair value by their investment managers using NAV as a practical expedient. Investments measured at NAV as a practical expedient for determining fair value are excluded from the fair value hierarchy.

The following tables provide summaries of the financial assets and financial liabilities measured at fair value in the statements of net assets grouped into the fair value hierarchy as at December 31, 2020 and 2019:

2020	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	**175**	**-**	**-**	**175**
Short-term investments	**-**	**16**	**-**	**16**
Fixed income	**-**	**3,787**	**-**	**3,787**
Marketable equity securities	**6,456**	**-**	**-**	**6,456**
Pooled funds	**-**	**1,976**	**-**	**1,976**
Derivative contracts	**-**	**1**	**-**	**1**
	6,631	**5,780**	**-**	**12,411**
Investments measured at NAV [1]				**2,176**
Payable to Province of Ontario for rate of return adjustment [2]				**(3,583)**
				11,004

2019	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	119	-	-	119
Short-term investments	-	14	-	14
Fixed income	-	3,591	-	3,591
Marketable equity securities	5,882	-	-	5,882
Pooled funds	-	1,728	-	1,728
Derivative contracts	-	1	-	1
	6,001	5,334	-	11,335
Investments measured at NAV [1]				2,136
Payable to Province of Ontario for rate of return adjustment [2]				(2,920)
				10,551

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented on the statements of net assets.

[2] Represents the cumulative excess in actual market return over the Committed Return based on the fair value of the Fund's assets related to the first 2.23 million used fuel bundles.

The tables above exclude receivables and payables.

There were no transfers between Level 1 and Level 2 and into or out of Level 3 during the reporting period.

Certain real estate investments were purchased from entities related to investment managers of the Fund. These entities were related to the investment manager due to common control. The real estate investments were measured at the exchange amount of the consideration paid as established by third-party real estate appraisers. The recorded amount of consideration paid in 2020 was $14 million (2019 – nil) and proceeds received in 2020 were $2 million (2019 – nil).

8. ELIGIBLE NUCLEAR COSTS

The ONFA sets out a process that must be followed prior to any amounts being disbursed from the Fund and gives the Province the right to review and approve all disbursements for eligible costs associated with long-term used fuel waste management. All disbursements to date have been made to OPG. The NFWA imposes additional restrictions on disbursements from the Trust. As at December 31, 2020, no disbursements have been made from the Trust since its inception.

Eligible costs from inception to December 31, 2020 were as follows:

	Annual	Inception-to-date
2020	**112**	**718**
2019	89	606
Inception to 2018	n/a	517

n/a – not applicable

9. INVESTMENT MANAGEMENT AND ADMINISTRATION FEES

Investment management and administration fees for the years ended December 31, 2020 and 2019 were as follows:

	2020	2019
Investment management fees	**53**	45
Custodian fees	**1**	1
Other administration fees (audit, consulting, and legal)	**2**	-
	56	46

For the year ended December 31, 2020, the ratio of expenses over net assets was 0.5 percent (2019 − 0.4 percent).

10. PROVINCE OF ONTARIO RATE OF RETURN ADJUSTMENT

In 2020, the actual rate of return of the Fund was a gain of 9.2 percent (2019 – 13.5 percent), after expenses, which was higher than the Committed Return of 3.9 percent (2019 – 4.8 percent), equal to an annual rate of return of 3.25 percent (2019 – 3.25 percent) plus an annual inflation component of 0.6 percent (2019 − 1.5 percent). This resulted in an increase of $663 million in the Province of Ontario rate of return adjustment payable during the year ended December 31, 2020 (2019 − $937 million). As at December 31, 2020, the Fund had a payable to the Province of $3,583 million (2019 – $2,920 million) for the rate of return adjustment.

11. INVESTMENT INCOME RECEIVABLE

The following table summarizes investment income receivables that were outstanding as at December 31, 2020 and 2019:

	2020	2019
Interest receivable	**19**	18
Dividends receivable and other receivables	**14**	13
	33	31

12. COMMITMENTS

The Fund has committed to entering into real asset investments, which may be funded over the next several years in accordance with the agreed-upon terms and conditions. As at December 31, 2020, these commitments totalled $1,023 million (2019 – $878 million). The investments in real assets are generally not redeemable.

13. COVID-19 PANDEMIC

The outbreak of the disease caused by a novel strain of coronavirus, identified as “COVID-19," since the beginning of the 2020 year has resulted in governments worldwide enacting a range of emergency measures to combat the spread of the virus. These measures, which have included the implementation of lockdowns, travel bans, self-imposed quarantine periods and physical distancing requirements, have caused material disruption to many businesses globally, resulting in an economic slowdown and financial market volatility. Governments and central banks in Canada and the United States have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions and promote economic recovery. The duration and ultimate impact of the COVID-19 pandemic is unknown at this time, as is the ultimate efficacy of the government and central bank interventions. It is not possible to reliably estimate the length and extent of these developments and the impact, if any, on the financial results and condition of the Fund in future periods.

Board Staff Interrogatory #79

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / Tables 2 and 3
Exhibit C2 / Tab 1 / Schedule 1 / Attachment 1

Preamble:

Attachment 1 at Exhibit C2 / Tab 1 / Schedule 1 provides the approved quarterly contributions for the UFF and Decommissioning Segregated Fund (DF). The UFF shows contributions from March 31, 2017 to December 31, 2021. The DF shows contributions from March 31, 2017 to December 31, 2024. In Tables 2 and 3 at Exhibit C2 / Tab 1 / Schedule 1, the nuclear segregated fund balance contributions are shown from 2016 to 2026.
Question(s):

a) Please explain why the approved quarterly contributions for the UFF are only disclosed up to December 31, 2021 while the approved quarterly contributions for the DF are disclosed up to December 31, 2024 in Attachment 1 at Exhibit C2 / Tab 1 / Schedule 1.

b) Please explain how OPG has determined the forecasted contributions for 2022 to 2026.

c) Please confirm that OPG has not had to make any contributions since 2017 and is not forecasting to make any contributions up to 2026, though contributions have been rebalanced between the funds.

Response

a) There are no quarterly contributions for the UFF beyond December 31, 2021 and for the DF beyond December 31, 2024 for any station based on the current contribution schedule approved by the Province of Ontario under the ONFA and therefore none are shown in Attachment 1 of Ex. C2-1-1.

b) As noted at Ex. C2-1-1, p. 12, lines 5-8, the forecasted contributions for 2022 to 2026 reflect the current contribution schedule approved by the Province of Ontario under the ONFA, based on the approved 2017-2021 ONFA reference plan currently in effect. (Note: the above reference cites Attachments 1 and 2 for the approved contribution schedule; however, it should solely refer to Attachment 1).

c) OPG confirms that it has not made cash contributions to the nuclear segregated funds since 2017 and that the same is true for the forecast of contributions reflected in the application based on the current approved ONFA contribution schedule. Actual contribution requirements beyond 2021 will be governed by a new contribution schedule to be developed and approved based on the ONFA reference plan for the 2022-2026 period.

Board Staff Interrogatory #80

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2

Preamble:

In the 2019 AFS at Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2, note 10 includes a table showing the change in OPG's portion of nuclear liabilities attributed to the prescribed facilities for the 2019 year-end of $10,425 million and for the 2018 year-end of $9,968 million. Table 2 at Exhibit C2 / Tab 1 / Schedule 1 provides the components of the ARO and shows a 2019 and 2018 year-end ARO of $10,412 million and $9,956 million, respectively.

Question(s):

a) Please explain and reconcile the difference in the 2019 and 2018 year-end ARO balances, as well as the components of the balances, between the financial statements and Table 2.

Response

The differences in year-end ARO liabilities and their constituent components as between the financial statements for the prescribed facilities and Ex. C2-1-1 Table 2 relate to OPG's obligation for spent cobalt-60. As discussed at Ex. G2-2-1, section 3.2, OPG has accepted the liability for the interim and future disposal of Bruce Power's spent cobalt-60 in exchange for annual revenue payments from Bruce Power. As these payments are intended to recover the costs of the liability, OPG excludes it from the revenue requirement impact of the nuclear liabilities presented at Ex. C2-1-1. The costs are also not funded under, and cannot be drawn from the ONFA.

Board Staff Interrogatory #81

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / Tables 2-3

Preamble:

Tables 2 and 3 at Exhibit C2 / Tab 1 / Schedule 1 show expenditures for used fuel, waste management and decommissioning (Line 5) in the ARO and contributions (Line 15) in the segregated funds.

Question(s):

a) Please confirm that the expenditures for used fuel, waste management and decommissioning include contributions to the segregated funds and the costs for used fuel management and L&ILW storage incurred during the stations' operating lives, which are internally funded costs to OPG.

b) Please provide the expenditures for internally funded costs from 2014 to 2026.

c) Please explain any other reasons for the difference between the expenditures and contributions.

d) Please explain how OPG forecasted internally funded costs for 2020 to 2026.

e) Please provide a table comparing the forecasted internally funded costs approved in prior OPG proceedings to actual internally funded costs incurred (or forecast to be incurred) for 2014 to 2026.

Response

a) and c)

Not confirmed. Contributions to the nuclear segregated funds (at lines 15 of Ex. C2-1-1, Tables 2-3) represent amounts added to the segregated funds, as determined based on the difference between funding liabilities and segregated fund balances under the Ontario Nuclear Funds Agreements, for purposes of funding eligible expenditures in the future. Expenditures for used fuel, waste management and decommissioning include both those reimbursed from the segregated funds (at lines 16 of Ex. C2-1-1, Tables 2-3) and those funded internally by OPG (i.e., the

difference between the total expenditures at line 5 and receipts form the segregated funds at line 16, of Ex. C2-1-1 Tables 2-3). Thus, contributions and expenditures are different concepts.

b) and e)

Attachment 1 provides the requested information. As there was no OEB-approved amount for 2016, the 2016 budget from EB-2016-0152 is used.

d) OPG plans and manages internally funded expenditures for used fuel, waste management and decommissioning in a similar manner to OM&A and capital expenditures. Hence, the forecasts for these expenditures are developed, reviewed and approved through OPG's business planning process described in Ex. A2-2-1 and Ex. F2-1-1.

Used Fuel, Waste Management & Decommissioning Internal Funded Costs $M	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Prescribed - 2014-2020 Actual & EB-2020-0290 (a)[1]	(66.8)	(85.1)	(90.3)	(128.9)	(101.4)	(101.8)	(173.3)	(196.6)	(187.1)	(158.4)	(169.7)	(179.8)	(109.0)
Prescribed - Forecasted in Prior Proceedings (b)[2]	(86.2)	(81.1)	(96.1)	(133.1)	(142.2)	(112.4)	(131.6)	(123.3)					
Prescribed - Comparison (a) - (b)	19.4	(4.1)	5.8	4.1	40.8	10.6	(41.7)	(73.3)					
Bruce - 2014-2020 Actual & EB-2020-0290 (a)[1]	(60.6)	(50.7)	(101.0)	(80.8)	(62.3)	(100.0)	(101.7)	(90.8)	(93.5)	(95.1)	(72.5)	(52.9)	(69.9)
Bruce - Forecasted in Prior Proceedings (b)[2]	(78.8)	(83.4)	(110.2)	(86.5)	(93.3)	(104.9)	(81.3)	(71.4)					
Bruce - Comparison (a) - (b)	18.2	32.7	9.2	5.7	31.1	4.8	(20.4)	(19.4)					

Notes:

1) 2014-2015 per EB-2016-0152, Ex. C2-1-1, Tables 2&3: line 5 less line 15. 2016-2019 per Ex. C2-1-1, Tables 2&3: line 5 less line 16. 2020 per Ex. L-A2-02-Staff-002, Table 7, col. (a) & col. (b): line 5 less line 16. 2021-2026 per Ex. C2-1-1, Tables 2&3: line 5 less line 16.

2) 2014-2015 per EB-2013-0321, Ex. C2-1-1, Tables 2&3: line 7 less line 17. 2016 per EB-2016-0152, Ex. C2-1-1, Tables 2&3: line 8 less line 15. 2017-2021 per EB-2016-0152, Ex.N1-1-1, Tables 3&4: line 8 less line 15.

Board Staff Interrogatory #82

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 15

Preamble:

In its discussion of the methodology used (and previously approved by the OEB) to recover the costs of nuclear liabilities for the prescribed facilities, OPG explained that accounting accretion expense on the ARO and earnings on the segregated funds do not directly form part of the revenue requirement for the prescribed facilities. OPG further stated that the return component of the recovery methodology effectively replaces the net amount of accretion expense and segregated fund earnings recorded for financial accounting purposes.

Question(s):

a) Please explain whether this statement is OPG's interpretation of the relationship between the return component and the accretion expense and segregated fund earnings. If not, please provide the basis for this statement.

b) Please provide OPG's position on the appropriateness of replacing the net amount of accretion expense and segregated fund earnings with the return component of the recovery methodology.

Response

a) The referenced statement is OPG's interpretation. While the OEB's Decision with Reasons in EB-2007-0905 provides a discussion of the conceptual underpinnings of the return component as part of the prescribed facilities' methodology, OPG has been unable to identify the specific basis for, and therefore evaluate each of the computational elements of the formula for this component.

For additional context, below OPG provides some of its interpretational observations on the relationship between the return component and the accretion expense and segregated fund earnings in the context of the above OEB decision.

OPG believes that the following observations made by the OEB in its EB-2007-0905 Decision with Reasons recognized the conceptual need for recovery of accretion in setting the currently approved methodology for the prescribed facilities,

given that nuclear liabilities and associated asset retirement costs are initially recorded on a present value basis:

> *Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its 26 nuclear liabilities whether they are funded or not.* (p. 90) …
>
> *The Board disagrees with CCC's submission that OPG should earn no return on unfunded amounts. Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its nuclear liabilities whether they are funded or not.* (p. 91)

OPG observes that the financial accounting elements of accretion expense (and segregated fund earnings) would not be included as part of a revenue requirement methodology that also includes asset retirement costs in rate base. Doing so could result in duplication. It appears to OPG that once the OEB determined in EB-2007-0905 that a rate base approach was appropriate, this naturally led to the exclusion of the financial accounting basis of accretion expense and segregated fund earnings from the methodology, with recovery of accretion instead considered through the return component. (For greater clarity, in either scenario, depreciation of asset retirement costs would form part of the recovered amounts.)

Additionally, in establishing the return component, the OEB's decision appears to identify the portion of nuclear liabilities that has been funded by OPG but not yet recovered from ratepayers as attracting the full weighted average cost of capital. For example, this feature appears in the following passages from the OEB's Decision with Reasons in EB-2007-0905:

> *The Board will require that the return on a portion of the rate base be limited to the average accretion rate on OPG's nuclear liabilities, which is currently 5.6%. That portion of rate base that attracts that return will be equal to the lesser of: (i) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. When the average unfunded nuclear liabilities exceed the amount of unamortized ARC in fixed assets, then the portion of rate base that attracts the 5.6% return would be capped at the average amount of unamortized ARC; if the average unfunded liabilities are forecast to be lower than the average unamortized ARC, it is appropriate to limit the portion of rate base that attracts the 5.6% return to the unfunded amount. That approach*

> *recognizes that OPG has raised debt (or used its retained earnings) to fund part of the unamortized ARC.* (p. 90)

OPG observes that the consideration of the funded yet unrecovered portion of the nuclear liabilities attracting the weighted average cost of capital would not be captured in the financial accounting elements of accretion expense and segregated fund earnings.

b) Please refer to Ex. L-C2-01-Staff-085 (a) – (c).

Board Staff Interrogatory #83

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 17

Preamble:

OPG stated that for the segregated funds, fund earnings are forecasted at the target rate of 5.15% consistent with the discount rate per the approved 2017 ONFA Reference Plan, and fund disbursements.

Question(s):

a) Please provide the actual annual rate of return on the segregated funds from 2014 to 2020.

b) For 2014 to 2020, please provide the annual weighted average actual rate of return on the segregated funds, after capping the return of the first 2.23 million fuel bundles at the guaranteed rate of return.

Response

a) OPG's actual annual rates of return on the Decommissioning Segregated Fund and Used Fuel Segregated Fund are provided in Chart 1 below, before the impact of the Provincial rate of return guarantee for the portion of the Used Fuel Segregated Fund attributed to the first 2.23 million used fuel bundles. The rates presented recognize that, as noted at Ex. C2-1-1, p. 13, line 22 to p. 14, line 6, when the funds are in a surplus position, earnings are recognized at the rate of growth of the underlying funding liability per the approved ONFA reference plan in effect (as OPG does not have any right to the surplus funding).

Chart 1
Actual Rates of Return on Segregated Funds (%)

	2014	2015	2016	2017	2018	2019	2020
Decommissioning Fund	5.15	5.15	5.15	5.15	5.15	5.15	5.15
Used Fuel Fund	11.43	5.15	5.15	5.15	5.15	5.15	5.15

b) OPG's actual annual rates of return on the Decommissioning Segregated Fund and Used Fuel Segregated Fund are provided in Chart 2 below, after the impact of the Provincial rate of return guarantee for the portion of the Used Fuel Segregated Fund attributed to the first 2.23 million used fuel bundles. As in part a), the rates presented recognize that when the funds are in a surplus position, earnings are recognized at the rate of growth of the underlying funding liability per the approved ONFA reference plan in effect.

For clarity, the rate of return guarantee on earnings for the portion of the Used Fuel Segregated Fund attributed to the first 2.23 million is not a "cap" but rather a risk reduction mechanism. The guarantee works in both directions in that it serves to increase fund returns when market returns are below the guaranteed rate and to decrease fund returns when market returns are above the guaranteed rate.

Chart 2
Actual Rates of Return on Segregated Funds after Impact of Provincial Guarantee (%)

	2014	2015	2016	2017	2018	2019	2020
Decommissioning Fund	5.15	5.15	5.15	5.15	5.15	5.15	5.15
Used Fuel Fund[1]	6.86	4.55	5.15	5.15	5.15	5.15	5.15

[1] For applicable years, calculated as the arithmetic weighted average, by opening fund balance, of the return rate for the fund portion attributed to the first 2.23 million used fuel bundles and the return rate for the remaining portion.

Board Staff Interrogatory #84

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / pp. 18, 21-22
Exhibit C2 / Tab 1 / Schedule 1 / Tables 1, 1a
Exhibit G2 / Tab 2 / Schedule 1 / p. 10

Preamble:

On page 18 at Exhibit C2 / Tab 1 / Schedule 1, OPG discussed income taxes associated with the prescribed facilities' nuclear liabilities. The income tax impact for the prescribed facilities is shown in Note 2 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1a, where income tax is determined by adjusting the pre-tax revenue requirement for items that are either deductible for tax purposes, but not for accounting purposes, or deductible for accounting purposes, but not for tax purposes (i.e. contributions, disbursements, expenditures).

On page 10 at Exhibit G2 / Tab 2 / Schedule 1, OPG indicated that the deferred income tax expense for Bruce is determined in accordance with generally accepted accounting principles for unregulated entities.

On page 21 at Exhibit C2 / Tab 1 / Schedule 1, OPG discussed income taxes for Bruce's nuclear liabilities. OPG stated that, as the cost elements of nuclear liabilities for Bruce are not deductible for tax purposes, they attract a deferred income tax credit. OPG further stated that Bruce Lease net revenues amounts are subject to regulatory income tax treatment through their impact on regulatory earnings before tax for the prescribed facilities. Note 3 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1a, shows the impact on Bruce's income taxes. These amounts are fully offset by the income tax impact on revenue requirement as shown in Line 16 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1.

Question(s):

a) Please confirm that the tax treatment for Bruce nuclear liabilities is calculated on a deferred taxes payable method, while for the prescribed facilities, taxes are calculated on a current taxes payable method. If not confirmed, please explain the tax basis for the tax calculations for each of the Bruce and prescribed facilities.

b) Please confirm that if Bruce nuclear liabilities were calculated using a current taxes payable method, the same calculation as used for the prescribed facilities as shown in Exhibit C2 / Tab 1 / Schedule 1 / Tables 1 / Line 7 would apply. If not, please

explain how the tax impact for Bruce nuclear liabilities would be calculated using the current taxes payable method.

Response

a) Confirmed.

b) OPG confirms that if the current taxes payable method were used for the Bruce facilities, the resulting calculations at lines 14 and 16 of Ex. C2-1-1, Table 1 would achieve the same impact as the calculation at line 7 of Ex. C2-1-1, Table 1 for the prescribed facilities.

Board Staff Interrogatory #85

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / p. 25
EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 96-98

Preamble:

In the OEB's findings on the nuclear liabilities revenue requirement methodology in OPG's 2017-2021 Payment Amounts Proceeding, OPG was directed to file a jurisdictional study for cost recovery methodologies of nuclear liabilities. In the current application, OPG proposed to recover nuclear liabilities using the same methodology as approved in OPG's 2008-2009 Payment Amounts proceeding[1] and subsequent proceedings.

Question(s):

a) Given the OEB's findings on the nuclear liabilities revenue requirement methodology in the 2017-2021 Payment Amounts Proceeding and the direction to file a jurisdictional study, please explain whether OPG has considered any alternative methods of recovery for nuclear liabilities for the 2022 to 2026 period.

b) If so, please discuss OPG's consideration of these alternatives and whether any of these alternatives were deemed to be appropriate.

c) Please provide supporting rationale for OPG's proposal to continue to use the methodology as approved in OPG's 2008-2009 Payment Amounts proceeding.

d) If OPG was approved to recover nuclear liabilities using a different methodology than currently proposed, please explain whether there would be any transitional matters to consider and what these matters may be.

Response

a) to c)

KPMG's jurisdictional study of cost recovery methodologies for nuclear liabilities identified two potentially applicable methods to OPG's prescribed facilities – the forward-looking funding requirement methodology and the accounting expense

[1] EB-2007-0905.

methodology (Section 28 of Ex. C2-1-1, Attachment 2). OPG's consideration of these methodologies is summarized below.

For OPG, the forward-looking funding methodology is similar to a cash-based methodology that was raised by the parties in the EB-2016-0152 proceeding. In its EB-2016-0152 Reply Argument (pp. 182-202), OPG set out extensive submissions against a change to the cash-based methodology. Having considered the findings of the jurisdictional study, OPG continues to hold the view that, although applied widely for US regulated utilities, a cash-based methodology is not appropriate in OPG's situation.

As highlighted in the jurisdictional study, there are a number of key differences between OPG's circumstances and those of the US utilities, including the upfront funding profile under the Ontario Nuclear Funds Agreement (Section 28.3 of Ex. C2-1-1, Attachment 2), the role of the US regulatory commissions in effecting the actual funding amounts based on underlying variables (Section 5.2 of Ex. C2-1-1, Attachment 2), and the fact that US utilities have been subject to a funding-based methodology since inception (pp. 5-6 and pp. 139-140 of Ex. C2-1-1, Attachment 2).

Given the extent of OPG's submissions in the EB-2016-0152 Reply Argument, they are not detailed in this response. For reference, key highlights of the submissions included OPG's explanations that:

- Its contribution requirements under the Ontario Nuclear Funds Agreement do not represent a proper measurement basis for OPG's costs because they are severely front-loaded to prior periods, rather than being matched to the productive life and output of the nuclear stations; thereby creating significant inter-generational equity and fairness concerns.
- A pay-as-you-go recovery methodology for internally funded expenditures on nuclear waste management and decommissioning would similarly result in a mismatch between the incurrence of the cost at the time of generation output and the period of cash outlay, such that amounts recovered in a given period would bear little relationship to electricity then consumed.
- If a cash-based methodology were to be adopted on a prospective basis, without adequate consideration of transitional impacts, OPG and its shareholder would be deprived of an ability recover the full cost of the nuclear liabilities and therefore experience a financial and accounting loss; this would be inconsistent with the thrust of O. Reg. 53/05 to keep OPG whole on the issue of nuclear liabilities.
- An ONFA-based methodology is inherently less transparent, as it would be based on a complex bilateral contract between OPG and the Province of Ontario that at times requires interpretation by the parties and can be amended if the

two parties agree, and over which the OEB has stated it does not have authority.[2]

The current approved methodology for the prescribed facilities is, to a large degree, an accounting-based methodology. It leverages accounting values determined in accordance with generally accepted accounting principles, such as depreciation expense, with the exception of replacing the net amount of accretion expense and segregated fund earnings with the return on rate base for the asset retirement cost balance (Ex. C2-1-1, Section 4.1). As set out in the EB-2016-0152 Reply Argument, OPG continues to hold the view that an accounting-based methodology is superior to a cash-based method for OPG. Key highlights of those submissions included:

- An accounting methodology provides better matching of the nuclear liabilities costs to the productive life and output of the nuclear stations, thereby minimizing inter-generational inequity concerns and providing for a fairer outcome for both customers and OPG.
- An accounting methodology provides better transparency to the rate-setting process as it is aligned with OPG's financial reporting and based on an established, common set of accounting principles and requirements.
- An accounting methodology typically supports greater stability in recovery amounts due to the amortization of cost impacts over the remaining asset life, compared, for example, to inherent unevenness of cash outlays for internally funded expenditures.
- Continuing with an accounting-based methodology mitigates the need for material transition adjustments that would need to be considered in the case of a switch to a cash-based methodology.

While OPG has not conducted an in-depth analysis on the topic, it considered whether the current methodology for the prescribed facilities could be modified to include accretion expense and segregated fund earnings, rather than the return on rate base component. This would have the benefit of aligning the methodology with that for the Bruce facilities' portion of the nuclear liabilities. In OPG's view, this would also have the benefit of greater transparency than the current methodology for the return component. For example, as discussed in Ex. L-C2-01-Staff-082, OPG has been unable to identify the specific basis for each of the computational elements of the return component formula based on the OEB's EB-2007-0905 Decision with Reasons.

Conversely, OPG recognizes that one of the implications of the current approach is that ratepayers are not exposed to investment performance risk for the prescribed

[2] EB-2013-0321, Decision with Reasons, p. 110.

facilities' portion of the segregated funds (Ex. C2-1-1, p. 15, lines 15-17), whereas a pure accounting methodology would likely lead to such increased exposure.[3]

Finally, OPG observed that, as a practical matter, the differences between the return on rate base component and the net of forecasted accretion expense and segregated fund earnings for the prescribed facilities is, in the overall context of nuclear liabilities, relatively modest over the 2022-2026 period, averaging about $10M per year (in favour of ratepayers).[4] Additionally, the value of the return on rate base component itself declines significantly by 2026, to just over $5M per year, as the Pickering asset retirement cost balance is fully depreciated.

On balance of the above considerations and in recognition that the current methodology has been applied since the company's first payment amounts proceeding, OPG did not further proceed with an analysis for transitioning to a pure accounting methodology for the prescribed facilities.

OPG did not consider any alternative recovery methodologies for the Bruce facilities' portion of the nuclear liabilities. In addition to these costs already being recovered using a pure accounting methodology, the OEB has previously determined that, in accordance with O. Reg. 53/05, sections 6(2)9 and 6(2)10, the costs of the nuclear liabilities (as well as other OPG revenues and costs that form part of Bruce Lease net revenues) are to be calculated using generally accepted accounting principles applicable to unregulated entities.

d) Neither OPG nor KPMG have conducted a specific analysis of transition matters and impacts that would arise if a different recovery methodology were to be adopted for OPG's nuclear liabilities. Given the complexity and potential magnitude of the issue, additional analysis would need to be undertaken with respect to any such transition once the target successor methodology has been identified. OPG's view is that any such transition should be undertaken when the full extent of the impacts and implications – both near and long term – has been understood and considered, and should not be in response to short-term changes, particularly given the very long-lived nature of the nuclear liabilities.

As an overriding principle, it is OPG's view that any transition should fairly consider the prospective economic impacts to customers, as well as to OPG and its shareholder, of having been subject to a different recovery methodology in the past. As OPG identified in EB-2016-0152 and updated in Ex. L-C2-01-Staff-086, any transition to a cash-based methodology, for example, should consider the material differences between amounts previously recovered under the current

[3] Given the inherent potential volatility of fund asset performance driven by external factors, this may include consideration of a variance account mechanism to manage the impact of such volatility.
[4] Based on pre-filed evidence at Ex. C2-1-1, Tables 1 and 2.

methodologies and those that would have been recovered under a cash-based methodology. As noted above, a prospective transition to a cash-based methodology would result in OPG experiencing a financial loss.

Board Staff Interrogatory #86

Interrogatory

Reference:
EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 96-98
EB-2016-0152 / Undertaking J20.7

Preamble:

In the OEB's findings on the nuclear liabilities revenue requirement methodology in OPG's 2017-2021 Payment Amounts proceeding, the OEB makes reference to amounts recovered pertaining to nuclear liabilities compared to requirements as provided in Undertaking J20.7 of that proceeding.

Question(s):

a) Please provide an update to the chart provided in EB-2016-0152 / Undertaking J20.7 so that the chart reflects the April 1, 2008 to December 31, 2026 period, including forecasted amounts as applicable.

Response

a) The requested information is provided at Attachment 1. As directed by the OEB at EB-2016-0152, Decision and Order, p. 97, OPG reports this information annually by June 30. In response to the OEB's direction that the time period of the report should start at April 1, 2008 at the latest, OPG has provided the information beginning April 1, 2005 in its reporting. Consistent with the presentation of the reporting and with EB-2016-0152, Ex. J20.7, the information at Attachment 1 begins at April 1, 2005.

Numbers may not add due to rounding.

Updated: 2021-07-09
EB-2020-0290
Exhibit L
C2-01-Staff-086
Attachment 1
Table 1

Table 1[1]
Summary of After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
April 1, 2005 to December 31, 2026

Line No.	Description	Note	Apr 1 2005 to Mar 31 2008	Apr 1 2008 to Dec 31 2016	Jan 1 2017 to Dec 31 2021	Jan 1 2022 to Dec 31 2026	Total Apr 1 2005 to Dec 31 2026
			(a)	(b)	(c)	(d)	(e)
			Note 2			Note 7	
	Prescribed Facilities						
1	**Total Amounts Recovered (after-tax)**	3	429.4	1,788.0	780.1	497.6	3,495.2
2	**Total Amounts Expended (after-tax)**	4	691.6	1,794.7	1,106.0	1,061.6	4,653.9
3	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 1 - line 2)		(262.2)	(6.7)	(325.8)	(564.0)	(1,158.7)
	Bruce Facilities						
4	**Total Amounts Recovered (after-tax)**	5	39.4	1,380.9	1,001.9	1,192.1	3,614.4
5	**Total Amounts Expended (after-tax)**	6	771.2	1,265.7	192.7	251.7	2,481.4
6	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 4 - line 5)		(731.8)	115.2	809.2	940.4	1,133.0
7	**Total Excess of Amounts Recovered over Amounts Expended (after-tax)** (line 3 + line 6)		(993.9)	108.5	483.3	376.4	(25.7)

Notes:

1 The following tax rates in effect during the corresponding periods were applied in the analysis: 2005 to 2007 - 34.12%, 2008 - 31.50%, 2009 - 31.00%, 2010 - 29.00%, 2011 - 26.50%, 2012 onwards - 25.00%.

2 As outlined in EB-2016-0152 Ex. C2-1-2, pp. 25-26, amounts recovered represent proxy amounts based on actual values for the period available from the EB-2007-0905 and EB-2010-0008 proceedings.

3 Col. (a) is from Table 2, line 5, col. (e). Col. (b) is from Table 3, line 7, col. (l). Col. (c) is from Table 4, line 7, col. (f). Col. (d) is from Table 5, line 7, col. (g).

4 Col. (a) is from Table 2, line 12, col. (e). Col. (b) is from Table 3, line 14, col. (l). Col. (c) is from Table 4, line 14, col. (f). Col. (d) is from Table 5, line 14, col. (g).

5 Col. (a) is from Table 2, line 19, col. (e). Col. (b) is from Table 3, line 19, col. (l). Col. (c) is from Table 4, line 19, col. (f). Col. (d) is from Table 5, line 19, col. (g).

6 Col. (a) is from Table 2, line 26, col. (e). Col. (b) is from Table 3, line 26, col. (l). Col. (c) is from Table 4, line 26, col. (f). Col. (d) is from Table 5, line 26, col. (g).

Numbers may not add due to rounding.

Table 2[1]
Proxy After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
April 1, 2005 to March 31, 2008

Line No.	Description	Apr 1 to Dec 31 2005	2006	2007	Jan 1 to Mar 31 2008	Total
		(a)	(b)	(c)	(d)	(e)
	Prescribed Facilities					
1	**Pre-tax Proxy Amounts Recovered**	132	156	225	53	566
2	**Reduction in Proxy Regulatory Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 8 x tax rate)	(72)	(116)	(79)	(13)	(281)
3	**Regulatory Income Taxes on Proxy Amounts Recovered** (line 1 + line 2) x tax rate / (1 - tax rate)	31	21	75	18	145
4	**Total Proxy Regulatory Income Taxes** (line 2 + line 3)	(42)	(95)	(4)	5	(136)
5	**After-tax Proxy Amounts Recovered** (line 1 + line 4)	90	61	221	57	429
6	**Contributions to Segregated Funds**	182	242	225	15	663
7	**Internally Funded Expenditures on Nuclear Liabilities**	31	98	8	28	165
8	**Total Amounts Expended (pre-tax)** (line 6 + line 7)	212	340	233	43	828
9	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 8 x tax rate)	(72)	(116)	(79)	(13)	(281)
10	**Income Taxes on Proxy Amounts Recovered** (line 5 x tax rate)	31	21	75	18	145
11	**Total Income Taxes** (line 9 + line 10)	(42)	(95)	(4)	5	(136)
12	**Total Amounts Expended (after-tax)** (line 8 + line 11)	171	245	229	47	692
13	**Excess of Proxy Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)** (line 1 - line 8)	(80)	(184)	(8)	10	(262)
14	**Excess of Proxy Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 5 - line 12)	(80)	(184)	(8)	10	(262)
	Bruce Facilities					
15	**Pre-tax Proxy Amounts Recovered**	87	114	179	34	414
16	**Reduction in Proxy Regulatory Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 23 x tax rate)	(59)	(85)	(207)	(37)	(388)
17	**Regulatory Income Taxes on Proxy Amounts Recovered** (line 15 + line 16) x tax rate / (1 - tax rate)	14	15	(14)	(2)	14
18	**Total Proxy Regulatory Income Taxes** (line 16 + line 17)	(45)	(69)	(221)	(39)	(374)
19	**After-tax Proxy Amounts Recovered** (line 15 + line 18)	42	45	(42)	(5)	39
20	**Contributions to Segregated Funds**	159	212	563	99	1,033
21	**Internally Funded Expenditures on Nuclear Liabilities**	15	36	43	19	113
22	**Total Amounts Expended (pre-tax)** (line 20 + line 21)	174	248	606	117	1,145
23	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Internally Funded Expenditures** (line 22 x tax rate)	(59)	(85)	(207)	(37)	(388)
24	**Income Taxes on Proxy Amounts Recovered** (line 19 x tax rate)	14	15	(14)	(2)	14
25	**Total Income Taxes** (line 23 + line 24)	(45)	(69)	(221)	(39)	(374)
26	**Total Amounts Expended (after-tax)** (line 22 + line 25)	129	179	385	79	771
27	**Excess of Proxy Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)** (line 15 - line 22)	(87)	(134)	(427)	(84)	(732)
28	**Excess of Proxy Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 19 - line 26)	(87)	(134)	(427)	(84)	(732)
29	**Total Excess of Proxy Amounts Recovered over Amounts Expended (pre-tax)** (line 13 + line 27)	(167)	(318)	(435)	(74)	(994)
30	**Total Excess of Proxy Amounts Recovered over Amounts Expended (after-tax)** (line 14 + line 28)	(167)	(318)	(435)	(74)	(994)

Notes:
1 OPG has used the presentation format required by the OEB in EB-2016-0152 Decision and Order, Page 97, adding additional line items to reflect the breakdown between Ontario Nuclear Funds Agreement contributions and internally funded expenditures on Nulcear Liabilities requested by the OEB. Amounts presented are otherwise unchanged form EB-2016-0152 Ex. J20.7.

Numbers may not add due to rounding.

Table 3[1]
After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
April 1, 2008 to December 31, 2016

Line No.	Description	Apr 1 to Dec 31 2008	2009	2010	Jan 1 to Feb 28 2011	Mar 1 to Dec 31 2011	2012	2013	Jan 1 to Oct 31 2014	Nov 1 to Dec 31 2014	2015	2016	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Prescribed Facilities												
1	**Total Amounts Recovered (pre-tax)**[2]	147.4	192.4	190.5	36.6	113.8	286.3	208.6	180.7	37.0	198.5	157.0	1,748.8
2	**Reduction in Regulatory Income Taxes for Contributions to Segregated Funds and Forecast Internally Funded Expenditures on Nuclear Liabilities**	(32.1)	(58.6)	(48.2)	(7.3)	(49.8)	(43.9)	(43.2)	(51.0)	(10.7)	(63.5)	(63.8)	(472.1)
3	**(Under)/Over Recovery Due to Differences Between Approved and Actual Nuclear Production**	2.4	4.2	4.4	(0.4)	3.1	1.7	5.3	3.2	(0.4)	4.4	3.0	31.0
4	**Total Reduction in Regulatory Income Taxes** (line 2 + line 3)	(29.7)	(54.4)	(43.8)	(7.7)	(46.7)	(42.2)	(37.9)	(47.8)	(11.0)	(59.1)	(60.8)	(441.1)
5	**Regulatory Income Taxes on Amounts Recovered** ((line 1 + line 4) x tax rate / (1-tax rate))	54.1	62.0	59.9	10.4	24.2	81.4	56.9	44.3	8.6	46.5	32.1	480.4
6	**Total Regulatory Income Taxes** (line 4 + line 5)	24.5	7.7	16.1	2.7	(22.5)	39.1	19.0	(3.5)	(2.4)	(12.6)	(28.7)	39.3
7	**Total Amounts Recovered (after-tax)** (line 1 + line 6)	171.8	200.1	206.6	39.4	91.3	325.4	227.7	177.2	34.6	185.9	128.3	1,788.0
8	**Contributions to Segregated Funds**	44.2	124.7	150.2	24.2	120.8	107.1	98.1	141.6	28.5	172.8	176.7	1,188.9
9	**Internally Funded Expenditures on Nuclear Liabilities**	32.1	63.6	60.2	11.3	57.4	73.9	60.0	45.1	21.7	85.1	90.3	600.7
10	**Total Amounts Expended (pre-tax)** (line 8 + line 9)	76.3	188.3	210.4	35.5	178.2	181.0	158.1	186.7	50.2	257.9	267.0	1,789.6
11	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 10 x tax rate)	(24.0)	(58.4)	(61.0)	(9.4)	(47.2)	(45.3)	(39.5)	(46.7)	(12.5)	(64.5)	(66.7)	(475.3)
12	**Income Taxes on Amounts Recovered** (line 7 x tax rate)	54.1	62.0	59.9	10.4	24.2	81.4	56.9	44.3	8.6	46.5	32.1	480.4
13	**Total Income Taxes** (line 11 + line 12)	30.1	3.6	(1.1)	1.0	(23.0)	36.1	17.4	(2.4)	(3.9)	(18.0)	(34.7)	5.1
14	**Total Amounts Expended (after-tax)** (line 10 + line 13)	106.4	191.9	209.3	36.5	155.2	217.1	175.5	184.3	46.3	239.9	232.3	1,794.7
15	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)** (line 1 - line 10)	71.1	4.1	(19.9)	1.2	(64.4)	105.3	50.5	(6.0)	(13.2)	(59.4)	(110.0)	(40.9)
16	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 7 - line 14)	65.4	8.1	(2.7)	2.9	(63.9)	108.3	52.2	(7.2)	(11.7)	(54.0)	(104.0)	(6.7)
	Bruce Facilities												
17	**Actual Bruce Lease Net Revenues Impact**	311.5	(32.6)	(68.6)	(8.5)	89.5	70.5	142.4	81.2	20.5	173.6	231.6	1,011.2
18	**Regulatory Income Tax Impact** (line 17 x tax rate / (1 - tax rate))	143.2	(14.6)	(28.0)	(3.1)	32.3	23.5	47.5	27.1	6.8	57.9	77.2	369.7
19	**Total Amounts Recovered (after-tax)** (line 17 + line 18)	454.7	(47.2)	(96.6)	(11.6)	121.8	94.0	189.9	108.3	27.4	231.5	308.8	1,380.9
20	**Contributions to Segregated Funds**	296.2	214.1	113.9	17.6	87.9	74.9	85.9	(26.2)	(5.1)	(29.4)	(26.9)	802.9
21	**Internally Funded Expenditures on Nuclear Liabilities**	34.9	23.8	19.3	6.6	37.5	55.6	59.6	41.2	19.4	50.7	101.0	449.6
22	**Total Amounts Expended (pre-tax)** (line 20 + line 21)	331.1	237.9	133.2	24.2	125.4	130.5	145.5	15.0	14.3	21.3	74.1	1,252.5
23	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Internally Funded Expenditures** (line 22 x tax rate)	(104.3)	(73.7)	(38.6)	(6.4)	(33.2)	(32.6)	(36.4)	(3.8)	(3.6)	(5.3)	(18.5)	(356.5)
24	**Income Taxes on Amounts Recovered** (line 19 x tax rate)	143.2	(14.6)	(28.0)	(3.1)	32.3	23.5	47.5	27.1	6.8	57.9	77.2	369.7
25	**Total Income Taxes** (line 23 + line 24)	38.9	(88.4)	(66.6)	(9.5)	(1.0)	(9.1)	11.1	23.3	3.3	52.6	58.7	13.3
26	**Total Amounts Expended (after-tax)** (line 22 + line 25)	370.0	149.5	66.6	14.7	124.4	121.4	156.6	38.3	17.6	73.8	132.8	1,265.7
27	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)** (line 17 - line 22)	(19.6)	(270.5)	(201.8)	(32.7)	(35.9)	(60.0)	(3.0)	66.2	6.2	152.4	157.5	(241.3)
28	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 19 - line 26)	84.7	(196.8)	(163.2)	(26.3)	(2.7)	(27.4)	33.3	70.0	9.8	157.7	176.0	115.2
29	**Total Excess of Amounts Recovered over Amounts Expended (pre-tax)** (line 15 + line 27)	51.5	(266.4)	(221.7)	(31.5)	(100.3)	45.3	47.5	60.2	(7.0)	92.9	47.5	(282.1)
30	**Total Excess of Amounts Recovered over Amounts Expended (after-tax)** (line 16 + line 28)	150.1	(188.6)	(165.9)	(23.4)	(66.6)	80.9	85.5	62.8	(1.9)	103.6	72.0	108.5

Notes:

1 OPG has used the presentation format required by the OEB in EB-2016-0152 Decision and Order, Page 97, adding additional line items to reflect the breakdown between Ontario Nuclear Funds Agreement contributions and internally funded expenditures on Nulcear Liabilities requested by the OEB. Amounts presented are otherwise unchanged form EB-2016-0152 Ex. J20.7.

2 Includes pre-tax revenue requirement impact, under/over recovery due to differences between approved and actual nuclear production, and pre-tax amounts recorded in the Nuclear Liabilities Deferral Account and the Impact of Changes in Station End-of-Life (2015) Deferral Account.

Numbers may not add due to rounding.

Updated: 2021-07-09
EB-2020-0290
Exhibit L
C2-01-Staff-086
Attachment 1
Table 4

Table 4[1]
After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
January 1, 2017 to December 31, 2021

Line No.	Description	Jan 1 to May 31 2017	Jun1 to Dec 31 2017	Total 2017	2018	2019	2020	2021	Total 2017-2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Prescribed Facilities								
1	**Total Amounts Recovered (pre-tax)**[2]	53.4	92.2	145.7	176.6	193.9	188.2	181.9	886.2
2	**Reduction in Regulatory Income Taxes for Contributions to Segregated Funds and Forecast Internally Funded Expenditures on Nuclear Liabilities**	(19.4)	(34.4)	(53.7)	(61.2)	(53.7)	(58.5)	(56.5)	(283.6)
3	**(Under)/Over Recovery Due to Differences Between Approved and Actual Nuclear Production**	3.9	(1.4)	2.5	(3.8)	(5.9)	(10.3)	0.0	(17.5)
4	**Total Reduction in Regulatory Income Taxes** (line 2 + line 3)	(15.5)	(35.7)	(51.2)	(65.0)	(59.6)	(68.8)	(56.5)	(301.1)
5	**Regulatory Income Taxes on Amounts Recovered** ((line 1 + line 4) x tax rate / (1-tax rate))	12.6	18.8	31.5	37.2	44.7	39.8	41.8	195.0
6	**Total Regulatory Income Taxes** (line 4 + line 5)	(2.8)	(16.9)	(19.7)	(27.8)	(14.9)	(29.0)	(14.6)	(106.1)
7	**Total Amounts Recovered (after-tax)** (line 1 + line 6)	50.6	75.4	125.9	148.8	179.0	159.1	167.3	780.1
8	**Contributions to Segregated Funds**	42.7	59.8	102.5	102.5	102.5	102.5	102.5	512.5
9	**Internally Funded Expenditures on Nuclear Liabilities**	51.3	77.6	128.9	101.4	101.8	173.3	196.6	702.1
10	**Total Amounts Expended (pre-tax)** (line 8 + line 9)	94.1	137.4	231.4	203.9	204.3	275.8	299.1	1,214.6
11	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 10 x tax rate)	(23.5)	(34.3)	(57.9)	(51.0)	(51.1)	(68.9)	(74.8)	(303.6)
12	**Income Taxes on Amounts Recovered** (line 7 x tax rate)	12.6	18.8	31.5	37.2	44.7	39.8	41.8	195.0
13	**Total Income Taxes** (line 11 + line 12)	(10.9)	(15.5)	(26.4)	(13.8)	(6.3)	(29.2)	(33.0)	(108.6)
14	**Total Amounts Expended (after-tax)** (line 10 + line 13)	83.2	121.9	205.1	190.1	198.0	246.6	266.1	1,106.0
15	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)** (line 1 - line 10)	(40.6)	(45.1)	(85.8)	(27.3)	(10.4)	(87.6)	(117.2)	(328.4)
16	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 7 - line 14)	(32.6)	(46.5)	(79.1)	(41.4)	(19.0)	(87.5)	(98.9)	(325.8)
	Bruce Facilities								
17	**Actual Bruce Lease Net Revenues Impact**	64.5	80.9	145.4	149.6	150.4	148.7	157.3	751.4
18	**Regulatory Income Tax Impact** (line 17 x tax rate / (1 - tax rate))	21.5	27.0	48.5	49.9	50.1	49.6	52.4	250.5
19	**Total Amounts Recovered (after-tax)** (line 17 + line 18)	86.0	107.9	193.9	199.4	200.5	198.3	209.7	1,001.9
20	**Contributions to Segregated Funds**	(42.7)	(59.8)	(102.5)	(102.5)	(102.5)	(102.5)	(102.5)	(512.5)
21	**Internally Funded Expenditures on Nuclear Liabilities**	31.6	49.2	80.8	62.3	100.0	101.7	90.8	435.5
22	**Total Amounts Expended (pre-tax)** (line 20 + line 21)	(11.1)	(10.6)	(21.7)	(40.2)	(2.5)	(0.8)	(11.7)	(77.0)
23	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 22 x tax rate)	2.8	2.7	5.4	10.1	0.6	0.2	2.9	19.2
24	**Income Taxes on Amounts Recovered** (line 19 x tax rate)	21.5	27.0	48.5	49.9	50.1	49.6	52.4	250.5
25	**Total Income Taxes** (line 23 + line 24)	24.3	29.6	53.9	59.9	50.8	49.8	55.4	269.7
26	**Total Amounts Expended (after-tax)** (line 22 + line 25)	13.2	19.0	32.2	19.7	48.3	48.9	43.6	192.7
27	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)** (line 17 - line 22)	75.6	91.5	167.1	189.8	152.9	149.6	169.0	828.4
28	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 19 - line 26)	72.8	88.9	161.7	179.7	152.3	149.4	166.1	809.2
29	**Total Excess of Amounts Recovered over Amounts Expended (pre-tax)** (line 15 + line 27)	34.9	46.4	81.3	162.5	142.5	62.0	51.8	500.0
30	**Total Excess of Amounts Recovered over Amounts Expended (after-tax)** (line 16 + line 28)	40.2	42.4	82.6	138.4	133.3	61.9	67.2	483.3

Notes:

1 OPG has used the presentation format required by the OEB in EB-2016-0152 Decision and Order, Page 97, adding additional line items to reflect the breakdown between Ontario Nuclear Funds Agreement contributions and internally funded expenditures on Nulcear Liabilities requested by the OEB.

2 Includes pre-tax revenue requirement impact, under/over recovery due to differences between approved and actual nuclear production, and pre-tax amounts recorded in the Nuclear Liability Deferral Account, the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account, the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account and the Capacity Refurbishment Variance Account in the applicable years.

Numbers may not add due to rounding.

Updated: 2021-07-09
EB-2020-0290
Exhibit L
C2-01-Staff-086
Attachment 1
Table 5

Table 5[1]
After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
January 1, 2022 to December 31, 2026

Line No.	Description	2022	2023	2024	2025	2026	Total 2022-2026
		(a)	(b)	(c)	(d)	(e)	(f)
	Prescribed Facilities						
1	**Total Amounts Recovered (pre-tax)**[2]	171.9	183.4	182.4	76.7	71.2	685.6
2	**Reduction in Regulatory Income Taxes for Contributions to Segregated Funds and Forecast Internally Funded Expenditures on Nuclear Liabilities**	(107.9)	(64.8)	(67.6)	(44.9)	(27.3)	(312.4)
3	**(Under)/Over Recovery Due to Differences Between Approved and Actual Nuclear Production**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total Reduction in Regulatory Income Taxes** (line 2 + line 3)	(107.9)	(64.8)	(67.6)	(44.9)	(27.3)	(312.4)
5	**Regulatory Income Taxes on Amounts Recovered** ((line 1 + line 4) x tax rate / (1-tax rate))	21.4	39.5	38.3	10.6	14.6	124.4
6	**Total Regulatory Income Taxes** (line 4 + line 5)	(86.5)	(25.2)	(29.3)	(34.4)	(12.6)	(188.0)
7	**Total Amounts Recovered (after-tax)** (line 1 + line 6)	85.4	158.2	153.1	42.4	58.5	497.6
8	**Contributions to Segregated Funds**	244.4	100.6	100.6	0.0	0.0	445.6
9	**Internally Funded Expenditures on Nuclear Liabilities**	187.1	158.4	169.7	179.8	109.0	804.1
10	**Total Amounts Expended (pre-tax)** (line 8 + line 9)	431.5	259.0	270.3	179.8	109.0	1,249.7
11	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 10 x tax rate)	(107.9)	(64.8)	(67.6)	(44.9)	(27.3)	(312.4)
12	**Income Taxes on Amounts Recovered** (line 7 x tax rate)	21.4	39.5	38.3	10.6	14.6	124.4
13	**Total Income Taxes** (line 11 + line 12)	(86.5)	(25.2)	(29.3)	(34.4)	(12.6)	(188.0)
14	**Total Amounts Expended (after-tax)** (line 10 + line 13)	345.0	233.8	241.0	145.4	96.4	1,061.6
15	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)** (line 1 - line 10)	(259.6)	(75.6)	(87.9)	(103.1)	(37.9)	(564.0)
16	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 7 - line 14)	(259.6)	(75.6)	(87.9)	(103.1)	(37.9)	(564.0)
	Bruce Facilities						
17	**Actual Bruce Lease Net Revenues Impact**	161.4	178.3	179.0	190.2	185.2	894.1
18	**Regulatory Income Tax Impact** (line 17 x tax rate / (1 - tax rate))	53.8	59.4	59.7	63.4	61.7	298.0
19	**Total Amounts Recovered (after-tax)** (line 17 + line 18)	215.2	237.7	238.7	253.6	247.0	1,192.1
20	**Contributions to Segregated Funds**	(244.4)	(100.6)	(100.6)	0.0	0.0	(445.6)
21	**Internally Funded Expenditures on Nuclear Liabilities**	93.5	95.1	72.5	52.9	69.9	383.9
22	**Total Amounts Expended (pre-tax)** (line 20 + line 21)	(150.9)	(5.6)	(28.1)	52.9	69.9	(61.7)
23	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Internally Funded Expenditures** (line 22 x tax rate)	37.7	1.4	7.0	(13.2)	(17.5)	15.4
24	**Income Taxes on Amounts Recovered** (line 19 x tax rate)	53.8	59.4	59.7	63.4	61.7	298.0
25	**Total Income Taxes** (line 23 + line 24)	91.5	60.8	66.7	50.2	44.3	313.5
26	**Total Amounts Expended (after-tax)** (line 22 + line 25)	(59.4)	55.3	38.6	103.1	114.2	251.7
27	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)** (line 17 - line 22)	312.3	183.8	207.1	137.3	115.3	955.8
28	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 19 - line 26)	274.6	182.4	200.1	150.5	132.8	940.4
29	**Total Excess of Amounts Recovered over Amounts Expended (pre-tax)** (line 15 + line 27)	52.7	108.2	119.2	34.2	77.4	391.8
30	**Total Excess of Amounts Recovered over Amounts Expended (after-tax)** (line 16 + line 28)	15.0	106.8	112.2	47.5	94.9	376.4

Notes:

1 OPG has used the presentation format required by the OEB in EB-2016-0152 Decision and Order, Page 97, adding additional line items to reflect the breakdown between Ontario Nuclear Funds Agreement contributions and internally funded expenditures on Nulcear Liabilities requested by the OEB.

2 Includes pre-tax revenue requirement impact and pre-tax amounts projected to be recorded in the Impact of Changes in Station End-of-Life (2017) Deferral Account, Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and Capacity Refurbishment Variance Account.

Board Staff Interrogatory #87

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / Attachment 2

Question(s):

a) Page 37 of the Nuclear Liability Cost Recovery Jurisdictional Study (the Jurisdictional Study) states, "In our US research we found in many instances that the accounting changes on adoption of FAS 143 were discussed in regulatory proceedings and that the utility commissions involved did not change how costs were recovered in rates." For those utilities noted (e.g. South Carolina, Florida, Georgia, Minnesota, North Carolina) where utility commissions did not require a change in cost recovery methodology upon adoption of FAS 143, please provide any further reasons beyond those noted in the report as provided by the utility commissions in deciding not to change how costs were recovered in rates.

b) Page 10 of the Jurisdictional Study discusses recovery methodologies including the "forward-looking funding requirements" and "accounting expense" methodologies. The forward-looking funding requirements methodology is based on amounts contributed to set-aside funds. The accounting expense methodology is based on expenses recognized in the financial statements. Please discuss OPG's views on whether the total recoveries under the two methodologies for OPG's nuclear liabilities should conceptually be equal after the nuclear liabilities are fully decommissioned.

c) Page 57 of the Jurisdictional Study indicates that for the utilities and jurisdictions reviewed in the U.S., recovery of nuclear decommissioning costs for investor-owned utilities is based on forward-looking funding approach. During KPMG LLP (KPMG)'s review of various jurisdictions in the U.S. for the purpose of selecting the jurisdictions to focus on, did KPMG come across any jurisdictions that recovered decommissioning costs based on an accounting approach? If so, please identify these jurisdictions and provide further details on the recovery methodology.

Response

The responses to parts a) and c) were prepared by KPMG. OPG prepared the response to part b).

a) In many of the US regulatory decisions noted, we found limited discussion of the rationale for retaining the current rate treatment upon adoption of accounting changes under FAS 143; this accounts for the limited discussion in the report.

In the case of Florida, the Notice of Adoption of Rule did not provide any rationale for retaining the current rate treatment.

In the case of Georgia, the order by the Georgia Public Service Commission that addressed FAS 143 was the approval of a settlement agreement and hence it contained limited discussion of issues generally and no discussion of the rate treatment of decommissioning costs that was adopted.

In the case of Minnesota, the Order by the Minnesota Public Utilities Commission did not cite any reasons for its decision to continue to set rates based on the existing forward-looking funding methodology.

In the case of North Carolina, our report noted that the North Carolina Utilities Commission (NCUC) had observed that the utilities based recoveries on a uniform expected earnings rate over the life of the facilities, whereas FAS 143 takes into account actual earnings realized in any year in computing that year's decommissioning expense. Wording in the NCUC Order suggests that the Commission viewed stability in the expense profile as an advantage, noting: "One of the advantages of the Commission's currently-approved method is that a long-term rate of return is assumed in a levelized manner over the life of the nuclear plants, and the amount included in cost of service is not subject to short-term market conditions. This is not the case under SFAS 143."

In practice, and notwithstanding the above statement by NCUC, we are not of the view that the forward-funding approach necessarily provides for more stable rates than an approach based on FAS 143. Actual required future collections under the forward-looking funding approach can be subject to significant changes as a consequence of past variances between actual and forecasted returns, particularly if there is a shorter remaining facility lifespan over which these impacts would be adjusted, and similarly as a result of changes in decommissioning cost estimates and expected facility lifespan. For example, Section 11.2.3 of our report highlighted the example of Diablo Canyon, where the utility initially proposed an increase in annual decommissioning expense from $67.8 million to $417.9 million as a result of updates to decommissioning cost estimates made as a result of the decision to close the facility and not seek a life extension. While a subsequent settlement proposal reduced the proposed expense amount to $112.5 million, the revised annual amount represented a significant increase over previous amounts collected from consumers.

In the case of South Carolina, the quote provided in our report included all of the specific factors identified by the Public Service Commission of South Carolina to support its decision.

b) OPG's view is that, conceptually, the two methodologies noted ("forward-looking funding requirements" and "accounting expense") should result in the same total payments by ratepayers over the full lifecycle of funding and incurring decommissioning and nuclear waste management expenditures. Specifically, both methodologies would need to be in place from the inception of the associated funding and accounting obligations until such time as all of the underlying decommissioning and nuclear waste management activities have been completed and the obligations discharged.

c) In our review of US jurisdictions, we did not come across any jurisdictions that we identified as recovering nuclear decommissioning costs based on an accounting expense methodology. As discussed further in our report, there were two utilities for which we could not definitively establish the specific approach to calculating the amounts recovered in rates. Nevertheless, for these utilities, we ultimately concluded that they were likely recovering costs based on a forward-looking funding approach. These utilities were:

- Oglethorpe Power Corporation, an Electricity Membership Cooperative (EMC) in the State of Georgia (Section 13.3).
- Los Angeles Department of Water and Power, a municipally-owned utility in the State of California (Section 11.3).

Each of these utilities has the authority to set its own rates without the involvement of an independent economic regulator. As a consequence, we found less publicly available information with respect to their calculations of decommissioning amounts recovered in rates, compared to a number of the other utilities reviewed.

In Canada, we note that rates at NB Power are being set in order to achieve specific equity targets. Because calculations of NB Power equity take into accounting measurements of decommissioning expense, these expenses are effectively the basis on which decommissioning costs are incorporated into utility rates. This is discussed in more detail in Section 19 of our report.