COST OF CAPITAL OVERVIEW

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER

1. The purpose of this evidence is to summarize Enbridge Gas's cost of capital and to provide a description of the evidence set out in Exhibit 5.

2. Table 1 provides the 2013 OEB-approved cost of capital and actual cost of capital from 2013 to 2018 for EGD. Table 2 provides the 2013 OEB-approved cost of capital and actual cost of capital from 2013 to 2018 for Union. Table 3 provides the actual cost of capital for 2019 to 2021 and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast of cost of capital for Enbridge Gas.

Table 1
Utility Cost of Capital - EGD

Line No.	Particulars	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Principal ($ millions)							
1	Long and Medium Term Debt	2,507.0	2,411.1	2,705.7	2,985.7	3,472.8	3,677.3	3,838.2
2	Short Term Debt	56.7	236.5	203.1	165.4	209.0	360.4	381.0
3	Preferred Shares (1)	100.0	100.0	100.0	100.0	100.0	100.0	87.5
4	Common Equity	1,498.3	1,545.6	1,692.5	1,828.7	2,127.2	2,327.5	2,422.5
5	Total	4,162.0	4,293.2	4,701.3	5,079.8	5,909.0	6,465.2	6,729.2
	Capital Structure (%)							
6	Long and Medium Term Debt	60.24	56.16	57.55	58.78	58.77	56.88	57.04
7	Short Term Debt	1.36	5.51	4.32	3.25	3.54	5.57	5.66
8	Preferred Shares (1)	2.40	2.33	2.13	1.97	1.69	1.55	1.30
9	Common Equity	36.00	36.00	36.00	36.00	36.00	36.00	36.00
10	Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	Cost Rate (%)							
11	Long and Medium Term Debt	5.79	5.84	5.41	5.15	4.95	4.86	4.72
12	Short Term Debt	2.00	1.11	1.38	1.32	1.33	1.05	1.81
13	Preferred Shares (1)	3.20	2.40	2.40	2.24	2.16	2.32	2.99
14	Common Equity	8.92	8.93	9.36	9.30	9.19	8.78	9.00
	Cost ($ millions)							
15	Long and Medium Term Debt	145.2	140.8	146.4	153.8	171.9	178.7	181.2
16	Short Term Debt	1.1	2.6	2.8	2.2	2.8	3.8	6.9
17	Preferred Shares (1)	3.2	2.4	2.4	2.2	2.2	2.3	2.6
18	Common Equity	133.7	138.0	158.4	170.1	195.5	204.4	218.0
19	Total	283.2	283.9	310.0	328.3	372.3	389.2	408.7

Note:
(1) On November 29, 2018, EGD redeemed all outstanding Group 3, Series D preference shares for $25.00 per share. No gain or loss was realized on the redemption.

Table 2
Utility Cost of Capital - Union

Line No.	Particulars	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Principal ($ millions)							
1	Long and Medium Term Debt	2,289.1	2,262.1	2,502.2	2,746.7	3,161.5	3,319.0	3,572.9
2	Short Term Debt	(1.3)	56.7	(60.5)	(143.5)	(219.5)	80.2	187.6
3	Preferred Shares (1)	102.3	102.9	103.2	103.0	103.4	104.1	91.3
4	Common Equity	1,344.4	1,362.2	1,431.5	1,522.2	1,713.0	1,970.6	2,166.6
5	Total	3,734.5	3,783.9	3,976.4	4,228.4	4,758.4	5,473.9	6,018.4
	Capital Structure (%)							
6	Long and Medium Term Debt	61.30	59.78	62.93	64.96	66.44	60.63	59.37
7	Short Term Debt	(0.03)	1.50	(1.52)	(3.40)	(4.61)	1.47	3.11
8	Preferred Shares (1)	2.74	2.72	2.59	2.44	2.17	1.90	1.52
9	Common Equity	36.00	36.00	36.00	36.00	36.00	36.00	36.00
10	Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	Cost Rate (%)							
11	Long and Medium Term Debt	6.53	6.51	6.03	5.64	5.12	4.98	4.51
12	Short Term Debt	1.31	1.15	1.19	0.84	0.82	1.02	1.72
13	Preferred Shares (1)	3.05	2.00	2.74	2.58	2.51	2.66	3.18
14	Common Equity	8.93	8.93	8.93	8.93	8.93	8.93	8.93
	Cost ($ millions)							
15	Long and Medium Term Debt	149.5	147.4	151.0	155.0	161.8	165.3	161.2
16	Short Term Debt	0.0	0.7	(0.7)	(1.2)	(1.8)	0.8	3.2
17	Preferred Shares (1)	3.1	2.0	2.8	2.7	2.6	2.8	2.9
18	Common Equity	120.0	121.6	127.9	135.9	153.0	176.0	193.5
19	Total	272.6	271.7	281.0	292.4	315.6	344.9	360.8

Note:
(1) On November 29, 2018, Union Gas redeemed all outstanding preference shares for the following amounts per share: Class A, Series A - $50.50; Class A, Series B - $55.00; Class A, Series C - $50.50 and Class B, Series 10 - $25.00. No gain or loss was realized on the redemption.

Table 3
Utility Cost of Capital - EGI

Line No.	Particulars	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)
	Principal ($ millions)						
1	Long and Medium Term Debt	8,002.0	8,568.5	8,505.3	9,079.6	9,628.8	10,028.1
2	Short Term Debt	407.0	111.1	596.5	521.8	318.3	6.2
3	Common Equity	4,730.0	4,882.3	5,119.8	5,400.8	5,595.2	6,150.0
4	Total	13,139.0	13,561.9	14,221.6	15,002.1	15,542.2	16,184.3
	Capital Structure (%)						
5	Long and Medium Term Debt	60.90	63.18	59.81	60.52	61.95	61.96
6	Short Term Debt	3.10	0.82	4.19	3.48	2.05	0.04
7	Common Equity	36.00	36.00	36.00	36.00	36.00	38.00
8	Total	100.00	100.00	100.00	100.00	100.00	100.00
	Cost Rate (%)						
9	Long and Medium Term Debt	4.45	4.38	4.37	4.24	4.18	4.17
10	Short Term Debt	2.04	0.94	0.31	2.40	3.00	3.00
11	Common Equity	8.98	8.52	8.34	8.66	8.66	8.66
	Cost ($ millions)						
12	Long and Medium Term Debt	356.1	375.3	371.3	385.0	402.5	418.0
13	Short Term Debt	8.3	1.0	1.9	12.5	9.5	0.2
14	Common Equity	424.8	416.0	427.0	467.7	484.5	532.6
15	Total	789.1	792.3	800.2	865.2	896.6	950.7

3. For the 2024 Test Year Enbridge Gas is requesting the OEB approve a cost of capital of $950.7 million.

4. Details regarding historical actuals for 2019 to 2021 and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast are provided at Exhibit 5 as set out below:

Exhibit 5, Tab 2, Schedule 1	Cost of Capital
Exhibit 5, Tab 3, Schedule 1	Capital Structure

COST OF CAPITAL

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER
WARREN REINISCH, DIRECTOR CASH TREASURY PLANNING

1. The purpose of this evidence is to request approval of Enbridge Gas's 2024 Test Year Forecast financing plan and the associated cost of capital. This evidence presents details for the 2019 to 2021 historical actuals, 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

2. This evidence is organized as follows:
    1. Summary
    2. Cost of Debt
    3. Return on Equity
    4. Financing Plans

1. Summary

3. Enbridge Gas's investment in rate base is financed by a combination of short-term and long-term debt and common equity. The current OEB-approved capital structure is based on a deemed 36% common equity component, with the remaining 64% financed through short and long-term debt. Enbridge Gas is proposing an increase to the common equity component of its capital structure to 42%. However, as detailed within Exhibit 5, Tab 3, Schedule 1, in consideration of the revenue requirement impacts of an increase to 42%, Enbridge Gas is proposing a phased-in transition to the proposed higher equity level. Enbridge Gas is proposing that common equity component be increased to 38% in 2024, and then a further 1% per year increase during the remainder of the price cap term, ultimately

reaching a 42% equity component in 2028. Please see Exhibit 5, Tab 3, Schedule 1 for details of this proposal.

4. Attachments 1 to 6 provide the following details for 2019 to 2024, respectively:
   a) Utility Cost of Capital Summary;
   b) Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return;
   c) Summary Statement of Principal and Carrying Cost of Term Debt;
   d) Unamortized Debt Discount and Expense; and
   e) Calculation of Cost Rates for Capital Structure Components.

5. Exhibit 5, Tab 1, Schedule 1, Table 3 summarizes the main components of the cost of capital shown in the attachments noted above.

6. Enbridge Gas's proposed capital structure for the 2024 Test Year is compared to the most recent OEB-approved capital structure in Table 1. Enbridge Gas as an amalgamated utility does not have a base OEB-approved cost of capital against which to compare 2024 Test Year results. In the absence of this, Enbridge Gas has combined the 2013 OEB-approved cost of capital parameters for comparison and illustration purposes. As a result, any variance analysis in this Exhibit assumes 2013 as the base year.

Table 1
Utility Cost of Capital - EGD, Union and EGI

Line No.	Particulars	2013 OEB-Approved EGD	2013 OEB-Approved Union	2013 OEB-Approved Combined	2024 Test Year EGI
		(a)	(b)	(c)	(d)
	Principal ($ millions)				
1	Long and Medium Term Debt	2,507.0	2,289.1	4,796.1	10,028.1
2	Short Term Debt	56.7	(1.3)	55.4	6.2
3	Preferred Shares (1)	100.0	102.3	202.3	0.0
4	Common Equity	1,498.3	1,344.4	2,842.7	6,150.0
5	Total	4,162.0	3,734.5	7,896.5	16,184.3
	Capital Structure (%)				
6	Long and Medium Term Debt	60.24	61.30	60.74	61.96
7	Short Term Debt	1.36	(0.03)	0.70	0.04
8	Preferred Shares (1)	2.40	2.74	2.56	0.00
9	Common Equity	36.00	36.00	36.00	38.00
10	Total	100.00	100.00	100.00	100.00
	Cost Rate (%)				
11	Long and Medium Term Debt	5.79	6.53	6.14	4.17
12	Short Term Debt	2.00	1.31	2.05	3.00
13	Preferred Shares (1)	3.20	3.05	3.11	0.00
14	Common Equity	8.92	8.93	8.92	8.66
	Cost ($ millions)				
15	Long and Medium Term Debt	145.2	149.5	294.7	418.0
16	Short Term Debt	1.1	0.0	1.1	0.2
17	Preferred Shares (1)	3.2	3.1	6.3	0.0
18	Common Equity	133.7	120.0	253.7	532.6
19	Total	283.2	272.6	555.7	950.7

Note:

(1) On November 29, 2018, EGD redeemed all outstanding Group 3, Series D preference shares for $25.00 per share and Union Gas redeemed all outstanding preference shares for the following amounts per share: Class A, Series A - $50.50; Class A, Series B - $55.00; Class A, Series C - $50.50 and Class B, Series 10 - $25.00. No gain or loss was realized on the redemption.

7. The increase in the 2024 Test Year cost of capital, compared to the 2013 OEB-approved costs, is due to an increase in total rate base and a proposed change in capital structure, partially offset by a lower weighted average cost of debt and a lower placeholder OEB formula Return on Equity (ROE).

2. Cost of Debt

2.1. Short-Term Debt

8. Enbridge Gas has access to a $2 billion, 364-day, credit facility which will expire in July 2023, at which time it is planned to be renewed. Short-term borrowing levels fluctuate significantly during the year (and year-to-year) due to Enbridge Gas's need to fund construction activities, the timing of long-term debt issuances and maturities, and the seasonal nature of Enbridge Gas's business, including the impact of fluctuating natural gas prices. The average amount of the short-term debt in the utility capital structure for 2024 is the difference between the average utility rate base and the total of the common equity component, and the long-term debt component. The difference between the short-term debt included in the utility capital structure and Enbridge Gas's average short-term borrowings for the period is related to the financing of items that are not included in utility rate base, primarily construction work in process (CWIP) and deferral account balances. The cost of short-term debt used in the cost of capital calculation reflects the projected Canadian Dealer Offered Rate (CDOR) which represents the 3-month bankers' acceptances plus a spread of 0.10% (based on historical trends and current market trading levels).

2.2. Long Term Debt

9. Long-term debt primarily consists of Medium Term Notes (MTN) that Enbridge Gas issues under the shelf prospectus[1] that currently allows it to issue up to $2 billion of MTNs in the Canadian debt capital markets. The MTN program allows Enbridge Gas to issue debt on a frequent and flexible basis to meet its financing needs. Debt can be issued with varying terms to manage the maturity profile of outstanding debt. Varying terms allows Enbridge Gas to manage refinancing risk in any one period while still prudently securing long-term financing. Enbridge Gas maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions.

10. To access the MTN market, issuers must maintain a public debt rating(s) issued by one or more of DBRS Limited (DBRS), Moody's Investor Service or Standard & Poor's Ratings Services (S&P). Table 2 provides details of Enbridge Gas's debt ratings. The ratings in Table 2 represent the most current available ratings of Enbridge Gas. The reports of S&P and DBRS are provided at Exhibit 1, Tab 8, Schedule 1, Attachments 11 and 12.

Table 2
Debt Ratings

Line No.	Particulars	Standard & Poor's (S&P)	Dominion Bond Rating Agency (DBRS)
1	MTN and Debentures	A-	A
2	Commercial Paper	A-1 (low)	R-1 (low)
3	Outlook / Trend	Stable	Stable

[1] The current shelf was filed on September 9, 2021, and expires on October 9, 2023.

11. Pricing on new issue debt is derived from observable trading levels in the secondary market of the issuer's outstanding debt and recent comparable transactions. The price of new issue debt is comprised of the yield on the Government of Canada (GoC) benchmark bond plus credit spread plus new issue concession[2]. To determine the credit spread, an appropriate Enbridge "on-the-run" secondary bond will be used as a reference (defined as the bond with ample trading liquidity, the amount outstanding, and the term to maturity that is near the typical on-the-run tenors of 2/3/5/7/10/30 years). Once the secondary bond is referenced, it will be curve-adjusted to get to the nearest on-the-run tenor. A new issue concession is sometimes required depending on market sentiment to incent investors to participate in the new offering instead of purchasing debt in the secondary market. The new issue concession is added to the credit spread at the time of issuance and is informed by recent transactions of issuers with similar credit. Once new issue spreads are determined, the total spread will be added to the yield of a benchmark GoC bond with a similar tenor. A curve adjustment will be added if needed to account for the tenor differential of the GoC benchmark used and new issue Enbridge Gas MTN.

12. Enbridge Gas's interest rate spreads have widened during 2022 as GoC benchmark bond rates and market volatility has increased. EGD 10-year spreads during 2011 were approximately 105bps. Enbridge Gas 10-year spreads in January 2022 were approximately 120 bps and by September 2022 were approximately 155bps.

[2] A new interest concession represents the interest rate spread between a new issuance and an existing long term debt issuance (of similar tenor) already traded in the market required to incent investors to invest in the new issuance. It will be determined by the market conditions at the time of a debt issuance.

13. The following formula is used to determine the coupon rate of a new long term bond issuance:

Indicate the term "time to maturity" of the newly issued bond

Identify the CAD GoC Benchmark bond with similar term

(A) Yield of the GoC Benchmark bond

+ (B) Spread (new indicative spread that includes the new issue concession)

+ (C) Curve Adjustment

= (D) Final Coupon

14. GoC benchmark bond interest rate forecasts are determined by taking the average of the forecasts from a group of banks that publish each rate. The group of banks used is made up of Canadian and international banks and the number of banks included in each forecasted rate range from three to seven banks, based on availability of forecast data. The Treasury group also factors in data from the most recent interest rate forward curves to ensure that bank forecasts are representative of forward market sentiment.

15. To develop a forecast credit spread, Enbridge Gas utilized a linear regression analysis. The analysis includes over 10 years of government, investment grade Canadian utility and Enbridge Gas bond data. The analysis used daily government and utility bond data and weekly Enbridge Gas bond data. Both 10 and 30-year tenors are included in the analysis.

16. To forecast future MTN issuances, Enbridge Gas used the forecast rate of the GoC benchmark bond for the planned year and tenor of issuance and then adds the Enbridge Gas spread from the regression analysis for the planned tenor.

The formula for calculating the interest on future MTN issuances is as follows:

(A) Yield of the GoC Benchmark bond (applicable issuance year and tenor)

+ (B) Spread

= (C) Forecasted Coupon

17. Interest rate risk arises when earnings and cash flows are adversely impacted by fluctuations in interest rates. Enbridge Gas is exposed to interest rate risk on both its floating rate short-term debt and prior to when long term fixed rate debt is priced. Interest rate risk is partially managed with hedges in order to mitigate the effect of interest rate changes on a portion of long-term fixed rate debt planned for issuance. The hedges apply only to the underlying GoC benchmark rate and not the Enbridge Gas credit spread. The impact of the hedges are incorporated into the effective interest rate of actual and forecast debit issuances.

18. The overall weighted average long-term debt rates for Enbridge Gas, as presented in annual cost of capital determinations, are calculated based on the carrying charges for all current and forecast debt issuances, over the actual and forecast outstanding principal, net of associated unamortized debt issuance and hedging costs (which offset the funds available to Enbridge Gas), related to those issuances. Details of the long-term debt rate calculations are provided at Attachments 1-6.

2.3. Fixed Financing Charges

19. Fixed financing charges applicable to Enbridge Gas's short- and long-term debt, included in utility revenue requirement, comprise costs that relate to:
    a) Debt Issuance and Admin Fees – professional advisory costs and rating agency fees associated with accessing long-term debt markets;
    b) Account Maintenance and Commitment Fees – upfront fees paid to credit facility agent(s) and lenders; and

c) Standby Fees – compensation charges for undrawn credit facility amounts.

20. The forecast fixed financing charges for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year are provided in Table 3.

Table 3
Forecast of Fixed Financing Charges

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(C)
1	Debt Issuance and Admin Fees	0.5	0.5	0.5
2	Account Maintenance Fees	1.4	1.5	1.5
3	Standby and Commitment Fees	2.0	2.0	2.0
4	Total	3.9	4.0	4.0

3. Return on Equity

21. Enbridge Gas's forecast revenue requirement for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year reflect an ROE of 8.66%, which represents the 2022 OEB formula ROE as a placeholder. The formula ROE calculation is based on the methodology set out in the Cost of Capital for Ontario's Regulated Utilities Report[3].

22. Enbridge Gas will update the equity return component of cost of capital for the 2024 Test Year upon the OEB providing its formula ROE for 2024 (expected in the fall of 2023).

23. The details of the ROE included as part of cost of capital is provided at Attachments 1 to 6.

[3] EB-2009-0084, Report of the OEB, Cost of Capital for Ontario's Regulated Utilities, December 11, 2009.

4. Financing Plans

24. Table 4 provides Enbridge Gas's financing plans with respect to long-term debt for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year. It is expected that the existing $2 Billion commercial paper program will be extended and a $2 Billion credit facility will continue to backstop the commercial paper program.

25. If necessary, additional liquidity is available through intercompany transactions with Enbridge and other related entities in the form of equity support or an affiliate credit facility priced at market terms.

26. Enbridge Gas is proposing to change the deemed capital structure as provided at Exhibit 5, Tab 3, Schedule 1. In accordance with the proposal to increase Enbridge Gas's common equity to 38% in 2024, Enbridge will subscribe for the necessary common equity of Enbridge Gas to support the proposed common equity level. This will require a capital contribution of approximately $324 million in the 2024 Test Year (38%-36% of $16,184.3 million Forecast Rate Base).

27. As a result of the higher level of equity financing proposed, the planned level of long-term debt issuances for the 2024 Test Year have been sized accordingly, noted in Table 4.

Table 4
Financing Plans - Medium Term Notes - Forecast Issuances and Retirements

Line No.	Year	Date (month)	Particulars	Term (years)	Coupon Rate	Issuance (Retirement) ($millions)
	(a)	(b)	(c)	(d)	(e)	(f)
1	2022	April	Medium-term notes due April 2022	16	4.85%	(125.0)
2	2022	July	Medium-term notes due July 2032	10	4.00%	650.0
3	2023	July	Medium-term notes due July 2033	10	4.20%	450.0
4	2023	July	Medium-term notes due July 2053	30	4.60%	450.0
5	2023	July	Medium-term notes due July 2023	10	6.05%	(100.0)
6	2023	July	Medium-term notes due July 2023	25	3.79%	(250.0)
7	2024	August	Medium-term notes due August 2024	10	3.15%	(215.0)
8	2024	December	Medium-term notes due December 2024	30	9.85%	(85.0)
9	2024	July	Medium-term notes due July 2034	10	4.00%	200.0
10	2024	July	Medium-term notes due July 2054	30	4.50%	200.0

28. The forecast issuances noted in Table 4 are included in the 2024 Test Year Cost of Capital provided at Attachment 6, as well as the respective 2022 Estimate and 2023 Bridge Year Cost of Capital parameters provided at Attachments 4 and 5, respectively.

29. As per the OEB's Filing Requirements[4], Section 2.5, Exhibit 5: Cost of Capital and Capital Structure, the 2024 Test Year weighted cost of debt corresponds with the debt rates of Enbridge Gas's actual and forecasted portfolio of debt for the test period, weighted by the principal of each debt instrument. Please see Attachment 6, pages 3-6 for details.

[4] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.

2019 Utility Cost of Capital Summary - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	8,002.0	60.90	4.45	2.71	356.1
2	Short Term Debt	407.0	3.10	2.04	0.06	8.3
3	Common Equity	4,730.0	36.00	8.98	3.23	424.8
4	Total	13,139.0	100.00		6.01	789.1

2019 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt	8,002.0	60.90	4.45	2.710
2	Short Term Debt	407.0	3.10	2.04	0.063
3	Total Debt	8,409.0	64.00		2.773
4	Common Equity	4,730.0	36.00	8.98	3.233
5	Total	13,139.0	100.00		6.006
6	Rate Base	13,139.0			
7	Utility Income	859.9			
8	Indicated Rate of Return	6.545%			
9	(Deficiency)/Sufficiency in Rate of Return (1)	0.539%			
10	Net (Deficiency)/Sufficiency	70.7			
11	Gross (Deficiency)/Sufficiency	96.2			
12	Revenue at Existing Rates	4,779.8			
13	Revenue Requirement	4,683.6			
14	Gross Revenue (Deficiency)/Sufficiency	96.2			
	Common Equity				
15	Allowed Rate of Return (1)	8.980%			
16	Earnings on Common Equity	10.475%			
17	(Deficiency)/Sufficiency In Common Equity Return (1)	1.495%			

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2019 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	250.0	3.79	3.87	9.7
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	125.0	4.85	4.91	6.1
15	June 2, 2021	200.0	2.76	2.85	5.7
16	October 1, 2028	650.0	3.65	3.65	23.7
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	100.0	6.05	6.383	6.4
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	175.0	4.77	5.31	9.3
26	November 23, 2020	200.0	4.04	5.209	10.4
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	200.0	4.04	2.801	5.6
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	215.0	3.15	3.241	7.0
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5
34	September 11, 2025	400.0	3.31	3.619	14.5

2019 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6
37	September 6, 2028	187.5	3.32	3.37	6.3
38	August 9, 2029	150.0	2.37	3.225	4.8
39	August 9, 2049	112.5	3.01	3.027	3.4
40	Total - Medium Term Notes	8,210.0			358.1
	Long Term Debentures				
41	December 2, 2024	85.0	9.85	9.91	8.4
42	Total - Long Term Debentures	85.0			8.4
43	Total	8,295.0			366.5

2019 Unamortized Debt Discount and Expense - Actual - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	47.6
2	January 31	47.2
3	February	46.7
4	March	46.2
5	April	45.8
6	May	45.4
7	June	45.0
8	July	44.4
9	August	79.7
10	September	78.9
11	October	78.0
12	November	77.3
13	December	76.8
14	Average of Monthly Averages	58.1

2019 Calculation of Cost Rates for Capital Structure Components - Actual - EGI

Line No.	Particulars	Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
		(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt			
1	Debt Summary	8,295.0	366.5	
2	Unamortized Finance Costs	(58.1)	-	
3	Percentage Allocation of Debt to Unregulated	(234.9)	(10.5)	
4	Total	8,002.0	356.0	
5	Calculated Cost Rate			4.45
	Short Term Debt			
6	Calculated Cost Rate			2.04
	Common Equity			
7	OEB Approved Formula ROE (1)			8.98

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2020 Utility Cost of Capital Summary - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	8,568.5	63.18	4.38	2.77	375.3
2	Short Term Debt	111.1	0.82	0.94	0.01	1.0
3	Common Equity	4,882.3	36.00	8.52	3.07	416.0
4	Total	13,561.9	100.00		5.84	792.3

2020 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	8,568.5	63.18	4.38	2.767
2	Short Term Debt	111.1	0.82	0.94	0.008
3	Total Debt	8,679.6	64.00		2.775
4	Common Equity	4,882.3	36.00	8.52	3.067
5	Total	13,561.9	100.00		5.842
6	Rate Base	13,561.9			
7	Utility Income	801.9			
8	Indicated Rate of Return	5.913%			
9	(Deficiency)/Sufficiency in Rate of Return (1)	0.071%			
10	Net (Deficiency)/Sufficiency	9.6			
11	Gross (Deficiency)/Sufficiency	13.1			
12	Revenue at Existing Rates	4,266.7			
13	Revenue Requirement	4,253.6			
14	Gross Revenue (Deficiency)/Sufficiency	13.1			
	Common Equity				
15	Allowed Rate of Return (1)	8.520%			
16	Earnings on Common Equity	8.717%			
17	(Deficiency)/Sufficiency In Common Equity Return (1)	0.197%			

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2020 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	250.0	3.79	3.87	9.7
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	125.0	4.85	4.91	6.1
15	June 2, 2021	200.0	2.76	2.85	5.7
16	October 1, 2028	189.6	3.65	3.65	6.9
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	100.0	6.05	6.383	6.4
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	175.0	4.77	5.31	9.3
26	November 23, 2020	175.0	4.04	5.209	9.1
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	175.0	4.04	2.801	4.9
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	215.0	3.15	3.241	7.0
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5
34	September 11, 2025	400.0	3.31	3.619	14.5
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6

2020 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
37	September 6, 2028	0.0	3.32	3.37	0.0
38	August 9, 2029	400.0	2.37	3.225	12.9
39	August 9, 2049	300.0	3.01	3.027	9.1
40	April 1, 2030	425.0	2.9	3.41	14.5
41	April 1, 2050	425.0	3.65	3.67	15.6
42	Total - Medium Term Notes	8,799.6			376.8
	Long Term Debentures				
43	December 2, 2024	85.0	9.85	9.91	8.4
44	Total - Long Term Debentures	85.0			8.4
45	Total	8,884.6			385.2

2020 Unamortized Debt Discount and Expense - Actual - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	76.8
2	January 31	76.1
3	February	75.3
4	March	74.6
5	April	82.0
6	May	81.2
7	June	80.4
8	July	79.6
9	August	78.9
10	September	78.1
11	October	77.3
12	November	76.5
13	December	75.7
14	Average of Monthly Averages	78.0

2020 Calculation of Cost Rates for Capital Structure Components - Actual - EGI

Line No.	Particulars	Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
		(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt			
1	Debt Summary	8,884.6	385.3	
2	Unamortized Finance Costs	(78.0)	-	
3	Percentage Allocation of Debt to Unregulated	(238.1)	(10.4)	
4	Total	8,568.5	374.9	
5	Calculated Cost Rate			4.38
	Short Term Debt			
6	Calculated Cost Rate			0.94
	Common Equity			
7	OEB-Approved Formula ROE (1)			8.52

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2021 Utility Cost of Capital Summary - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	8,505.3	59.81	4.37	2.61	371.3
2	Short Term Debt	596.5	4.19	0.31	0.01	1.8
3	Common Equity	5,119.8	36.00	8.34	3.00	427.0
4	Total	14,221.6	100.00		5.63	800.1

2021 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Actual - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	8,505.3	59.81	4.37	2.611
2	Short Term Debt	596.5	4.19	0.31	0.013
3	Total Debt	9,101.8	64.00		2.624
4	Common Equity	5,119.8	36.00	8.34	3.002
5	Total	14,221.6	100.00		5.626
6	Rate Base	14,221.6			
7	Utility Income	842.5			
8	Indicated Rate of Return	5.924%			
9	(Deficiency)/Sufficiency in Rate of Return (1)	0.298%			
10	Net (Deficiency)/Sufficiency	42.4			
11	Gross (Deficiency)/Sufficiency	57.7			
12	Revenue at Existing Rates	4,628.6			
13	Revenue Requirement	4,570.9			
14	Gross Revenue (Deficiency)/Sufficiency	57.7			
	Common Equity				
15	Allowed Rate of Return (1)	8.340%			
16	Earnings on Common Equity	9.168%			
17	(Deficiency)/Sufficiency In Common Equity Return (1)	0.828%			

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2021 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	250.0	3.79	3.87	9.7
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	125.0	4.85	4.91	6.1
15	June 2, 2021	83.3	2.76	2.85	2.4
16	October 1, 2028	0.0	3.65	3.65	0.0
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	100.0	6.05	6.383	6.4
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	167.7	4.77	5.31	8.9
26	November 23, 2020	0.0	4.04	5.209	0.0
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	0.0	4.04	2.801	0.0
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	215.0	3.15	3.241	7.0
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5
34	September 11, 2025	400.0	3.31	3.619	14.5
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6

2021 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
37	September 6, 2028	0.0	3.32	3.37	0.0
38	August 9, 2029	400.0	2.37	3.225	12.9
39	August 9, 2049	300.0	3.01	3.027	9.1
40	April 1, 2030	600.0	2.90	3.41	20.5
41	April 1, 2050	600.0	3.65	3.67	22.0
42	September 1, 2031	138.5	2.60	2.94	4.1
43	September 1, 2051	124.0	3.50	3.22	4.0
44	Total - Medium Term Notes	8,748.5			372.6
	Long Term Debentures				
45	December 2, 2024	85.0	9.85	9.91	8.4
46	Total - Long Term Debentures	85.0			8.4
47	Total	8,833.5			381.0

2021 Unamortized Debt Discount and Expense - Actual - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	100.9
2	January 31	99.8
3	February	98.8
4	March	97.7
5	April	96.7
6	May	95.6
7	June	94.6
8	July	93.5
9	August	92.5
10	September	121.8
11	October	120.5
12	November	119.2
13	December	118.0
14	Average of Monthly Averages	103.3

2021 Calculation of Cost Rates for Capital Structure Components - Actual - EGI

Line No.	Particulars	Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
		(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt			
1	Debt Summary	8,833.5	381.0	
2	Unamortized Finance Costs	(103.3)	-	
3	Percentage Allocation of Debt to Unregulated	(224.9)	(9.8)	
4	Total	8,505.3	371.2	
5	Calculated Cost Rate			4.36
	Short Term Debt			
6	Calculated Cost Rate			0.31
	Common Equity			
7	OEB-Approved Formula ROE (1)			8.34

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2022 Utility Cost of Capital Summary - Estimate - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	9,079.6	60.52	4.24	2.57	385.0
2	Short Term Debt	521.8	3.48	2.40	0.08	12.5
3	Common Equity	5,400.8	36.00	8.66	3.12	467.7
4	Total	15,002.1	100.00		5.77	865.2

2022 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Estimate - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	9,079.6	60.52	4.24	2.566
2	Short Term Debt	521.8	3.48	2.40	0.084
3	Total Debt	9,601.4	64.00		2.650
4	Common Equity	5,400.8	36.00	8.66	3.118
5	Total	15,002.1	100.00		5.767
6	Rate Base	15,002.1			
7	Utility Income	889.4			
8	Indicated Rate of Return	5.929%			
9	(Deficiency)/Sufficiency in Rate of Return (1)	0.161%			
10	Net Sufficiency (Deficiency)	24.2			
11	Gross (Deficiency)/Sufficiency	32.9			
12	Revenue at Existing Rates	5,095.3			
13	Revenue Requirement	5,062.4			
14	Gross Revenue (Deficiency)/Sufficiency	32.9			
	Common Equity				
15	Allowed Rate of Return (1)	8.660%			
16	Earnings on Common Equity	9.108%			
17	(Deficiency)/Sufficiency In Common Equity Return (1)	0.448%			

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2022 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	250.0	3.79	3.87	9.7
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	46.9	4.85	4.91	2.3
15	June 2, 2021	0.0	2.76	2.85	0.0
16	October 1, 2028	0.0	3.65	3.65	0.0
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	100.0	6.05	6.383	6.4
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	0.0	4.77	5.31	0.0
26	November 23, 2020	0.0	4.04	5.209	0.0
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	0.0	4.04	2.801	0.0
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	215.0	3.15	3.241	7.0
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5

2022 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
34	September 11, 2025	400.0	3.31	3.619	14.5
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6
37	September 6, 2028	0.0	3.32	3.37	0.0
38	August 9, 2029	400.0	2.37	3.225	12.9
39	August 9, 2049	300.0	3.01	3.027	9.1
40	April 1, 2030	600.0	2.90	3.41	20.5
41	April 1, 2050	600.0	3.65	3.67	22.0
42	September 1, 2031	475.0	2.60	2.94	14.0
43	September 1, 2051	425.0	3.50	3.22	13.7
44	July 1, 2032	297.9	4.00	3.32	9.9
45	July 1, 2052	0.0	3.70	3.75	0.0
46	Total - Medium Term Notes	9,354.8			387.0
	Long Term Debentures				
47	December 2, 2024	85.0	9.85	9.91	8.4
48	Total - Long Term Debentures	85.0			8.4
49	Total	9,439.8			395.4

2022 Unamortized Debt Discount and Expense - Estimate - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	118.0
2	January 31	116.8
3	February	115.6
4	March	114.3
5	April	113.1
6	May	111.9
7	June	110.7
8	July	112.9
9	August	111.6
10	September	110.4
11	October	109.1
12	November	107.9
13	December	106.6
14	Average of Monthly Averages	112.2

2022 Calculation of Cost Rates for Capital Structure Components - Estimate - EGI

Line No.	Particulars	Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
		(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt			
1	Debt Summary	9,439.8	395.4	
2	Unamortized Finance Costs	(112.2)	-	
3	Percentage Allocation of Debt to Unregulated	(248.0)	(10.5)	
4	Total	9,079.6	384.9	
6	Calculated Cost Rate			4.24
	Short Term Debt			
7	Calculated Cost Rate			2.40
	Common Equity			
8	OEB-Approved Formula ROE (1)			8.66

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2023 Utility Cost of Capital Summary - Bridge Year - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	9,628.8	61.95	4.18	2.59	402.5
2	Short Term Debt	318.3	2.05	3.00	0.06	9.5
3	Common Equity	5,595.2	36.00	8.66	3.12	484.5
4	Total	15,542.2	100.00		5.77	896.6

2023 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Bridge Year - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	9,628.8	61.97	4.18	2.590
2	Short Term Debt	318.3	2.03	3.00	0.061
3	Total Debt	9,947.0	64.00		2.651
4	Common Equity	5,595.2	36.00	8.66	3.118
5	Total	15,542.2	100.00		5.769
6	Rate Base	15,542.2			
7	Utility Income	955.1			
8	Indicated Rate of Return	6.145%			
9	(Deficiency)/Sufficiency in Rate of Return (1)	0.377%			
10	Net (Deficiency)/Sufficiency	58.5			
11	Gross (Deficiency)/Sufficiency	79.6			
12	Revenue at Existing Rates	5,809.7			
13	Revenue Requirement	5,730.0			
14	Gross Revenue (Deficiency)/Sufficiency	79.6			
	Common Equity				
15	Allowed Rate of Return (1)	8.660%			
16	Earnings on Common Equity	9.706%			
17	(Deficiency)/Sufficiency In Common Equity Return (1)	1.046%			

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2023 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	135.4	3.79	3.87	5.2
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	0.0	4.85	4.91	0.0
15	June 2, 2021	0.0	2.76	2.85	0.0
16	October 1, 2028	0.0	3.65	3.65	0.0
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	54.2	6.05	6.383	3.5
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	0.0	4.77	5.31	0.0
26	November 23, 2020	0.0	4.04	5.209	0.0
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	0.0	4.04	2.801	0.0
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	215.0	3.15	3.241	7.0
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5
34	September 11, 2025	400.0	3.31	3.619	14.5
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6

2023 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
37	September 6, 2028	0.0	3.32	3.37	0.0
38	August 9, 2029	400.0	2.37	3.225	12.9
39	August 9, 2049	300.0	3.01	3.027	9.1
40	April 1, 2030	600.0	2.90	3.41	20.5
41	April 1, 2050	600.0	3.65	3.67	22.0
42	September 1, 2031	475.0	2.60	2.94	14.0
43	September 1, 2051	425.0	3.50	3.22	13.7
44	July 1, 2032	650.0	4.00	3.32	21.6
45	July 1, 2052	0.0	3.70	3.75	0.0
46	July 1, 2033	206.3	4.20	3.28	6.8
47	July 1, 2053	206.3	4.60	4.62	9.5
48	Total - Medium Term Notes	9,912.2			405.6
	Long Term Debentures				
49	December 2, 2024	85.0	9.85	9.91	8.4
50	Total - Long Term Debentures	85.0			8.4
51	Total	9,997.2			414.0

2023 Unamortized Debt Discount and Expense - Bridge Year - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	106.6
2	January 31	105.4
3	February	104.1
4	March	102.9
5	April	101.6
6	May	100.4
7	June	99.1
8	July	103.0
9	August	101.7
10	September	100.4
11	October	99.2
12	November	97.9
13	December	96.7
14	Average of Monthly Averages	101.5

2023 Calculation of Cost Rates for Capital Structure Components - EGI

Line No.	Particulars	Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
		(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt			
1	Debt Summary	9,997.2	414.0	
2	Unamortized Finance Costs	(101.5)	-	
3	Percentage Allocation of Debt to Unregulated	(266.9)	(11.2)	
4	Total	9,628.8	402.8	
5	Calculated Cost Rate			4.18
	Short Term Debt			
6	Calculated Cost Rate			3.00
	Common Equity			
7	OEB-Approved Formula ROE (1)			8.66

Note:
(1) As approved in the EB-2017-0306/0307 Decision, for the purposes of determining any applicable earnings sharing amount, a 1.50% (or 150 basis point) ROE deadband was added to the annual OEB formula ROE.

2024 Utility Cost of Capital Summary - Test Year - EGI

Line No.	Particulars	Principal ($ millions) (a)	Component (%) (b)	Cost Rate (%) (c)	Cost Component (%) (d) = (b x c)	Cost ($ millions) (e) = (a x c)
1	Long and Medium Term Debt	10,028.1	61.96	4.17	2.58	418.0
2	Short Term Debt	6.2	0.04	3.00	0.00	0.2
3	Common Equity	6,150.0	38.00	8.66	3.29	532.6
4	Total	16,184.3	100.00		5.87	950.7

2024 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Test Year - EGI

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	10,028.1	61.96	4.17	2.582
2	Short Term Debt	6.2	0.04	3.00	0.001
3	Total Debt	10,034.3	62.00		2.584
4	Common Equity	6,150.0	38.00	8.66	3.291
5	Total	16,184.3	100.00		5.874
6	Rate Base	16,184.3			
7	Utility Income	755.9			
8	Indicated Rate of Return	4.670%			
9	(Deficiency)/Sufficiency in Rate of Return	(1.204%)			
10	Net (Deficiency)/Sufficiency	(194.9)			
11	Gross (Deficiency)/Sufficiency	(265.1)			
12	Revenue at Existing Rates	6,014.0			
13	Revenue Requirement	6,279.1			
14	Gross Revenue (Deficiency)/Sufficiency	(265.1)			
	Common Equity				
15	Allowed Rate of Return	8.660%			
16	Earnings on Common Equity	5.491%			
17	(Deficiency)/Sufficiency In Common Equity Return	(3.169%)			

2024 Summary Statement of Principal and Carrying Cost of Term Debt - Actual - EGI

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
	Medium Term Notes				
1	June 2, 2044	250.0	4.20	4.24	10.6
2	June 2, 2044	250.0	4.20	4.27	10.7
3	September 2, 2038	300.0	6.05	6.1	18.3
4	June 21, 2041	300.0	4.88	4.92	14.8
5	July 23, 2040	250.0	5.20	5.27	13.2
6	July 10, 2023	0.0	3.79	3.87	0.0
7	June 1, 2026	250.0	2.81	2.87	7.2
8	June 1, 2046	250.0	3.80	3.84	9.6
9	November 22, 2027	250.0	2.88	2.95	7.4
10	November 22, 2047	250.0	3.59	3.64	9.1
11	September 17, 2025	200.0	3.19	3.26	6.5
12	September 11, 2036	165.0	5.46	5.49	9.1
13	November 10, 2025	125.0	8.65	8.77	11.0
14	April 25, 2022	0.0	4.85	4.91	0.0
15	June 2, 2021	0.0	2.76	2.85	0.0
16	October 1, 2028	0.0	3.65	3.65	0.0
17	October 2, 2025	20.0	8.85	8.97	1.8
18	October 29, 2026	100.0	7.60	8.086	8.1
19	November 3, 2027	100.0	6.65	6.711	6.7
20	May 19, 2028	100.0	6.10	6.161	6.2
21	July 5, 2023	0.0	6.05	6.383	0.0
22	November 15, 2032	150.0	6.90	6.95	10.4
23	December 16, 2033	150.0	6.16	6.18	9.3
24	February 25, 2036	300.0	5.21	5.183	15.5
25	December 17, 2021	0.0	4.77	5.31	0.0
26	November 23, 2020	0.0	4.04	5.209	0.0
27	November 22, 2050	200.0	4.95	4.99	10.0
28	November 22, 2050	100.0	4.95	4.731	4.7
29	November 23, 2020	0.0	4.04	2.801	0.0
30	November 23, 2043	200.0	4.50	4.198	8.4
31	August 22, 2024	152.3	3.15	3.241	4.9
32	August 22, 2044	215.0	4.00	3.889	8.4
33	August 22, 2044	170.0	4.00	4.436	7.5
34	September 11, 2025	400.0	3.31	3.619	14.5
35	August 5, 2026	300.0	2.50	3.423	10.3
36	November 29, 2047	300.0	3.51	3.527	10.6

2024 Summary Statement of Principle and Carrying Cost of Term Debt - Actual - EGI (Continued)

Line No.	Maturity Date	Principal (Average of Monthly Averages) ($ millions)	Coupon Rate (%)	Effective Cost Rate (%)	Carrying Cost ($ millions)
		(a)	(b)	(c)	(d) = (a x c)
37	September 6, 2028	0.0	3.32	3.37	0.0
38	August 9, 2029	400.0	2.37	3.225	12.9
39	August 9, 2049	300.0	3.01	3.027	9.1
40	April 1, 2030	600.0	2.90	3.41	20.5
41	April 1, 2050	600.0	3.65	3.67	22.0
42	September 1, 2031	475.0	2.60	2.94	14.0
43	September 1, 2051	425.0	3.50	3.22	13.7
44	July 1, 2032	650.0	4.00	3.32	21.6
45	July 1, 2052	0.0	3.70	3.75	0.0
46	July 1, 2033	450.0	4.20	3.28	14.8
47	July 1, 2053	450.0	4.60	4.62	20.8
48	July 1, 2034	91.7	4.00	4.05	3.7
49	July 1, 2054	91.7	4.50	4.52	4.1
50	Total - Medium Term Notes	10,330.7			421.9
	Long Term Debentures				
51	December 2, 2024	85.0	9.85	9.91	8.4
52	Total - Long Term Debentures	85.0			8.4
53	Total	10,415.7			430.3

2024 Unamortized Debt Discount and Expense - Test Year - EGI

Line No.	Month / Day	Carrying Cost ($ millions)
1	January 1	96.7
2	January 31	95.4
3	February	94.2
4	March	92.9
5	April	91.7
6	May	90.4
7	June	89.2
8	July	93.0
9	August	91.7
10	September	90.4
11	October	89.1
12	November	87.9
13	December	86.6
14	Average of Monthly Averages	91.5

2024 Calculation of Cost Rates for Capital Structure Components - Test Year - EGI

Line No.	Particulars		Average of Monthly Averages ($ millions)	Carrying Cost ($ millions)	Calculated Cost Rate (%)
			(a)	(b)	(c) = (b / a)
	Long and Medium Term Debt				
1	Debt Summary		10,415.7	430.3	
2	Unamortized Finance Costs		(91.5)	-	
3	Percentage Allocation of Debt to Unregulated	2.87%	(296.1)	(12.3)	
4	Total		10,028.1	418.0	
5	Calculated Cost Rate				4.17
	Short Term Debt				
6	Calculated Cost Rate				3.00
	Common Equity				
7	OEB-Approved Formula ROE				8.66

CAPITAL STRUCTURE

TANYA FERGUSON, VICE PRESIDENT FINANCE & BUSINESS PARTNER

RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to request approval of a change to the deemed equity thickness component of Enbridge Gas's capital structure.

2. The OEB last approved equity thickness levels for EGD[1] and Union[2] in the 2013 Rates proceedings for each utility. An approved common equity of 36% has been in place for each of EGD and Union since that time. With the amalgamation of EGD and Union in 2019[3], which formed Enbridge Gas, the deemed common equity ratio for Enbridge Gas remained at 36%.

3. Enbridge Gas believes that significant changes in the environment in which it operates have occurred since the time of the 2013 Rates proceedings. The OEB's current cost of capital policy indicates that capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. In order to determine if its risk profile has significantly changed since 2012, Enbridge Gas retained Concentric Energy Advisors Inc. (Concentric) to prepare an independent report on the reasonableness of the capital structure currently approved by the OEB. Concentric's findings are set out in a report entitled "Enbridge Gas Inc. Common Equity Ratio Study" (the Study) and provided at Attachment 1.

4. Concentric considered changes in Enbridge Gas's business and financial risk since the OEB's last assessment (i.e. 2012). In the context of its consideration of business

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[1] EB-2011-0354.
[2] EB-2011-0210.
[3] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

and financial risk, Concentric concluded that Enbridge Gas's overall risk has significantly increased since 2012. As a result, Concentric concludes that the shift in risk profile warrants a reassessment of the Company's equity ratio.

5. Based on the increased risk profile of Enbridge Gas, Concentric recommends that the OEB approve an increase to the deemed equity ratio for Enbridge Gas from 36% to 42% to maintain financial strength and continued access to capital at a reasonable cost, and to manage the Energy Transition under a variety of economic and capital market conditions. As Concentric notes in the Study: "Our recommended equity ratio for Enbridge Gas in the upcoming rate setting period is consistent with the results of our analysis, which indicate that an increase in equity thickness is warranted. This is particularly important as the Company will need to maintain financial strength to continue accessing the debt and equity capital it needs to manage the Energy Transition under a variety of economic and capital market conditions, while providing safe and reliable service to its customers."

6. Enbridge Gas believes that an increase in its approved equity thickness to 42% is appropriate and supported by Concentric's findings. However, in order to manage the revenue requirement and rate impacts of the proposed change in equity thickness, along with the impacts of other proposals included within this Application, the Company proposes that the increase be phased in over the next incentive regulation term. As illustrated in Table 1, a 2% increase in equity thickness is proposed for the 2024 Test Year, with subsequent 1% increases in each of 2025 to 2028.

Table 1
Proposed Escalation of Equity Ratio

Line No.	Particulars (%)	2024	2025	2026	2027	2028
		(a)	(b)	(c)	(d)	(e)
1	Common Equity - Prior Year	36.0	38.0	39.0	40.0	41.0
2	Increase in Common Equity	2.0	1.0	1.0	1.0	1.0
3	Common Equity	38.0	39.0	40.0	41.0	42.0

7. The impact of increasing equity thickness from 36% to 38% in 2024, which is reflected in the requested test year deficiency, is an increase in revenue requirement of approximately $26.1 million, as provided at Exhibit 6, Tab 1, Schedules 1 and 2. An increase to 42% in 2024 would result in an increase in the revenue requirement of approximately $80.6 million, or an incremental $54.5 million. These revenue requirement impacts reflect the forecast cost of capital change that would occur between each level of equity thickness. As such, the increased return on equity at the 38% and 42% equity thickness levels, have been partially offset by corresponding reductions in debt financing. The $54.5 million revenue requirement variance between financing 2024 Rate Base at a 42% equity thickness level versus 38% level, is the total amount the Company is proposing to incorporate into rates through base rate adjustments in 2025 to 2028, in order to achieve the increase in equity thickness to 42% by 2028.

8. The revenue requirement impacts of changes to the 2024 equity thickness level were determined by calculating the cost of capital impacts that would result from forecast financing plan changes that would occur at each equity thickness level. As the level of equity thickness rises, the forecast level of 2024 term debt issuances

needed to fund rate base declines. With the changes in debt and equity requirements at each equity level, the balancing short-term debt levels required to fund rate base are also impacted.

9. As provided at Exhibit 5, Tab 2, Schedule 1, the 2024 Test Year Forecast term debt issuances of $400 million, included within the determination of the 2024 Test Year cost of capital, revenue requirement and associated deficiency, have been sized to reflect the phased increase in equity thickness to 38%. However, if the Company were assumed to remain at a 36% equity level in 2024, the forecast term debt issuances that would be required would double to $800 million (with a similar even split between 10 and 30 year terms, and similar effective rates), while an increase to a 42% equity level in 2024 would result in no term debt issuances being required. Table 2 summarizes the forecast cost of capital and the grossed-up (for taxes) cost of capital (or revenue requirement) for each equity level, the variance between each level, including the total and annual amounts to be incorporated as base rate adjustments in 2025 to 2028.

Table 2
2024 Equity Thickness Impacts on Cost of Capital and Revenue Requirement

Line No.	Particulars ($ millions)	Principal	Component	Cost Rate	Cost	Gross-up for taxes	Rev. Req. Impact
		(a)	(b)	(c)	(d)	(e)	(f)
	Equity thickness - 36%						
1	Medium and Long Term Debt	10206.0	63.06%	4.17%	425.6	-	425.6
2	Short Term Debt	152.0	0.94%	3.00%	4.6	-	4.6
3	Common Equity	5826.3	36.00%	8.66%	504.6	181.9	686.5
4	Cost of Capital component of Revenue Requirement	16184.3			934.8		1116.7
	Equity thickness - 38% (included in 2024 rev. req.)						
5	Medium and Long Term Debt	10028.1	61.96%	4.17%	418.0	-	418.0
6	Short Term Debt	6.2	0.04%	3.00%	0.2	-	0.2
7	Common Equity	6150.0	38.00%	8.66%	532.6	192.0	724.6
8	Cost of Capital component of Revenue Requirement	16184.3			950.7		1142.8
	Equity thickness - 42%						
9	Medium and Long Term Debt	9852.2	60.88%	4.17%	410.4	-	410.4
10	Short Term Debt	(465.3)	(2.9%)	3.00%	(14.0)	-	(14.0)
11	Common Equity	6797.4	42.00%	8.66%	588.7	212.2	800.9
12	Cost of Capital component of Revenue Requirement	16184.3			985.1		1197.3
13	2024 Revenue requirement impact of moving to 38% deemed equity thickness (from 36%)						26.1
14	2024 Revenue requirement impact of moving to 42% deemed equity thickness (from 36%)						80.6
15	42% versus 38% revenue requirement variance to be captured through base rate adjustments in 2025 - 2028						54.5
16	Proposed annual base rate adjustment in each of 2025 - 2028 (1/4 of $54.5 million)						13.6

10. As illustrated in Table 2, the incremental impact of increasing equity thickness to 42% in 2024, versus 38%, reflects an incremental $647.4 million of rate base to be funded through equity ((4% * 2024 rate base of $16,184.3 million) at the placeholder ROE of 8.66%, which grossed up for taxes causes a revenue requirement increase of $76.3 million, offset by a corresponding reduction in debt financing. As noted earlier, the reduction in debt financing would be accommodated by eliminating the forecast 2024 term debt issuances totaling $400 million (which due to their forecast issuance timing in July were only partially effective), with the residual accommodated through a reduction in short-term debt, with a combined carrying cost reduction $21.7 million. The net revenue requirement impact of increasing equity thickness an incremental 4% (to 42% versus the 38% reflected in the 2024 Test Year revenue requirement and deficiency) is the increase of $54.5 million that the Company proposes to incorporate into rates through base rate adjustments in 2025 to 2028.

11. In order to implement the proposed 1% increase in equity thickness in each year of the IR term (2025 to 2028), the Company proposes an annual base rate adjustment of $13.6 million. The annual base rate adjustment of $13.6 million is calculated as the incremental 2024 revenue requirement between an equity thickness of 42% and 38%, or $54.5 million, divided by the remaining four years of the IR term. In the derivation of annual rates, the Company proposes to include the annual base rate adjustment to the revenue requirement for rate-setting following the escalation of the previous year's rates. The base rate adjustment would then form part of base rates and be subject to escalation in subsequent years of the IR term. For instance, the $13.6 million base rate adjustment for 2025 would be added to the revenue requirement for rate-setting after price cap escalation was performed for 2025, but would be included in the base rates subject to price cap escalation in each of 2026 to 2028. The escalation of the base rate adjustment is consistent with escalation that

would have occurred had the revenue requirement implications of adopting a 42% equity thickness been fully adopted in 2024, as opposed to being phased in.

12. Consistent with Enbridge Gas's proposal to update the return on equity included in the 2024 Test Year revenue requirement (provided at Exhibit 5, Tab 2, Schedule 1), the Company correspondingly proposes to update the value of the 2025 to 2028 base rate adjustment to reflect the 2024 OEB formula ROE rate (expected to be released in the fall of 2023).

13. In summary, Enbridge Gas requests that the OEB approve the proposed increase in equity thickness to 42%, subject to the proposed phased in approach where 38% is reflected in 2024 rates, and subsequent 1% increases are reflected through annual base rate adjustments captured as part of the 2025 to 2028 rate proceedings as detailed above.

14. The 2024 Test Year impact of increasing Enbridge Gas's common equity ratio is included in the cost of capital details provided at Exhibit 5, Tab 2, Schedule 1.

ENBRIDGE GAS INC.
COMMON EQUITY RATIO STUDY

OCTOBER 17, 2022

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SECTION 1:
EXECUTIVE SUMMARY

Concentric Energy Advisors, Inc. ("Concentric") was retained to prepare this independent report as to the reasonableness of the capital structure currently authorized by the Ontario Energy Board ("OEB") for Enbridge Gas Inc. ("Enbridge Gas," "EGI," or the "Company"). Enbridge Gas' next rate application will cover the five-year period from 2024 to 2028.

Concentric followed the OEB's preferred approach to assessing capital structure for the utilities it regulates by beginning with a detailed risk analysis of Enbridge Gas, and specifically studying changes in Enbridge Gas' risk profile relative to the time when the OEB previously assessed the Company's capital structure. Enbridge Gas represents the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union Gas"). Therefore, our analysis compares the Company's risk profile today to the Company's risk profile in 2012, which is the approximate period in which EB-2011-0354 (i.e., the OEB's most recent equity thickness evaluation for EGD) and EB-2011-0210 (i.e., the OEB's most recent equity thickness evaluation for Union Gas) occurred.

In our assessment, Enbridge Gas' risk profile has increased significantly as compared to its risk profile at the time of EB-2011-0354 and EB-2011-0210. The most material factor contributing to the increase is the Energy Transition – a broad-scale transformation from a primary reliance on fossil fuels to a primary reliance on more renewable fuel sources. Investors perceive the Energy Transition as transforming the long-term risk environment for local gas distributors such as the Company. Moody's Investor Service ("Moody's") has opined that "[l]ong-term challenges to natural gas infrastructure are increasing" and that "carbon reduction commitments raise operating risks and cost of capital."[1] Wells Fargo stated that this represents "a stark change from 5+ years ago when LDCs were considered to offer more sustainable growth at a lower risk profile."[2]

Despite these challenges, the Company is actively positioning itself to mitigate the effects of the Energy Transition, and we expect the Company and the OEB will work together to minimize, to the extent possible, the risks it presents, while simultaneously protecting customers' interests. However, we conclude that the Energy Transition makes the Company's business significantly riskier today than it was in 2012 from an investor's perspective.

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1 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

2 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

We also find that there have been changes in other aspects of the Company's risk profile since 2012. In total, our study encompassed five primary aspects of the Company's risk profile: (1) Energy Transition risk, (2) Volumetric risk, (3) Financial risk, (4) Operational risk, and (5) Regulatory risk. Figure 1 summarizes the significant developments in each of these areas since EB-2011-0354 and EB-2011-0210, as well as our conclusions with respect to each risk area. We also examined independent market indicators regarding the riskiness of Canadian utility and gas utility investments, such as valuation multiples, Beta coefficients, and credit ratings. These indicators support our conclusion that the Company faces greater risk today than it did in 2012.

Figure 1: Risk Analysis Summary

Risk Category	Summary of Developments	Conclusion
Energy Transition	The Energy Transition began in earnest in the last five years. As investors and rating agencies widely recognize, it substantially affects the risk profile of North American gas distribution utilities, including Enbridge Gas.	**Significant Increase**
Volumetric	A weaker economic outlook, the introduction of competition from alternative gas suppliers, and increased competition from electricity (i.e., the Energy Transition) have combined to increase the Company's volumetric risk relative to EGI's previous equity thickness proceedings. Regulatory mechanisms provide short-term insulation, but do not change the long-term challenges facing the Company.	**Modest Increase**
Financial	EGI has experienced a gradual weakening in its debt-related credit metrics since 2012, and its credit profile is comparatively weak relative to the proxy group companies. The Company's credit spreads on debt issuances have widened slightly since 2012.	**Modest Increase**
Operational	The complexities of operating the utility have increased, putting pressure on the Company regarding project permitting, execution, and cost recovery. Successful management of the associated rate impacts depends on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices.	**Neutral to Modest Increase**
Regulatory	Straight-fixed-variable ("SFV") rate design reduces cost recovery risk, and the OEB's findings in EGI's Integrated Resource Planning ("IRP") proceeding provide a pathway for rate base treatment of IRP alternatives.	**Modest Decrease** *(Assuming SFV Approval)*

In accordance with OEB precedent, after determining that the Company's risk profile has significantly changed since 2012, we next developed an analysis of the appropriate equity ratio based on the Fair Return Standard ("FRS"). The FRS includes three components, none of which rank in priority to the others: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard. To arrive at an equity thickness recommendation that is consistent with the FRS, we examined the equity ratios of four different proxy groups, each screened to include companies with risk characteristics that are similar to Enbridge Gas. Further, we considered how Enbridge Gas compares to each of the proxy groups from a risk perspective. In addition, we considered recently deemed equity ratios for other regulated utilities in Ontario. Figure 47 at the end of this report summarizes the data points we found most meaningful in our FRS analysis.

Given the Company's increased risk profile and Enbridge Gas's risk relative to other North American gas and electric utilities, Concentric recommends that the Company's equity ratio be set between 40% and 45%. Within that range, Concentric recommends the OEB authorize a common equity ratio of 42% for the Company.[3]

Our recommended equity ratio for Enbridge Gas in the upcoming rate setting period is consistent with the results of our analysis, which indicate that an increase in equity thickness is warranted. This is particularly important as the Company will need to maintain financial strength to continue accessing the debt and equity capital it needs to manage the Energy Transition under a variety of economic and capital market conditions, while providing safe and reliable service to its customers.

Witness Duty

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

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

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

[3] Our understanding is that the Company, in order to mitigate customer bill impacts, is proposing to phase in the increase in its deemed equity ratio over the five-year term of the rate period, beginning at 38% in 2024, and increasing by 1% each year until reaching 42% in 2028.

SECTION 2:
SCOPE OF ANALYSIS AND OVERVIEW OF CONCENTRIC

Scope

Concentric was retained to conduct an independent capital structure review to assess the reasonableness of Enbridge Gas' current capital structure in preparation for Enbridge Gas' 2024 rebasing application. In preparing this report, Concentric developed the following:

1. An assessment of Enbridge Gas' business risk and financial risk compared to the last assessment that was reviewed by the OEB;
2. An assessment of Enbridge Gas' prospective business risk and financial risk;
3. An examination of information on utility actual and approved capital structures;
4. A comparison of other North American utility capital structures to Enbridge Gas' current and proposed capital structure; and
5. A specific recommended range and point estimate for the appropriate common equity level for Enbridge Gas.

Overview of Concentric

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has provided expert testimony on the cost of capital in more than 100 regulatory proceedings in Canada and the U.S. over the past five years.

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

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

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

Mr. Dane has more than 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has testified and provided expert reports on regulated ratemaking and utility performance matters for investor- and provincially-owned utilities, including on the cost of capital and capital structure, merger impacts, earnings sharing mechanisms and rate adjustment mechanisms, revenue requirements, lead-lag studies/cash working capital, and utility productivity and benchmarking. That testimony includes assessments of Ontario Power Generation's equity thickness before the OEB in EB-2016-0152 and EB-2020-0290. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the OEB, as discussed above. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

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

SECTION 3:
PRINCIPLES FOR A FAIR RETURN AND REGULATORY BACKGROUND

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

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[4]

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

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

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

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

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4 Northwestern, at 193.

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

> *The [NEB] is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*
>
> - *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
> - *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
> - *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*
>
> *In the [NEB]'s view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainlines revenue requirement, result in tolls that are just and reasonable.*[5]

Similarly, in its EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, (the "2009 Cost of Capital Report") the OEB discussed the necessity of adhering to the FRS as follows:

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

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[5] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].*[6]

Furthermore, the OEB has recognized that the cost of capital is a forward-looking concept. For example, in its decision in EB-2009-0084, the OEB referenced a presentation by Dr. Bill Cannon at CAMPUT's 2009 Energy Regulation Conference during which Dr. Cannon explained the forward-looking nature of the cost of capital as follows: "First, it [the cost of capital] is forward looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return."[7] Elsewhere in that same decision, the OEB stated: "First, the Board notes that the [Fair Return Standard] expressly refers to an opportunity cost of capital concept; one that is prospective rather than retrospective."[8] In other words, investors establish their return requirements based on expectations regarding economic growth, inflation, interest rates, the market risk premium and other factors affecting future risks and opportunity costs.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the OEB has expressed its view that "the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital."[9] Further, the OEB has determined that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities." However, the assessment of comparability "does not require that those entities be 'the same'."[10]

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6 Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i and 19.
7 *Id.*, at 25.
8 *Id.*, at 19.
9 *Id.*, at 20.
10 *Id.*, at 21.

Regarding capital structure specifically, the OEB's policy is to only re-evaluate a utility's deemed equity ratio in the event that its risk profile changes significantly. Specifically, in the 2009 Cost of Capital Report, the OEB found:

> *The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.*[11]

Concentric recognizes that the OEB has previously determined that the capital structure for a regulated utility will not be changed unless there is a demonstration that the utility's risk profile has materially changed since the previous review. However, this is not the standard used by investors to evaluate whether the authorized return (both ROE and capital structure) meets their return requirements. The comparable return standard also requires an analysis between the utility for which the return is being set and a peer group of companies with comparable risk. That is the purpose for establishing a risk-comparable proxy group. In our view, comparing changes in risk for the subject company over time does not provide a complete analysis of whether the capital structure remains appropriate. Despite this, we have developed the analysis in this report to address the OEB's two-stage test.

The OEB's Approach to Setting Equity Thickness for Enbridge Gas/Union Gas

The OEB's approach to setting capital structure in Ontario has evolved through a number of proceedings for both gas and electric distribution utilities. The OEB issues a generic ROE applicable to all utilities under its jurisdiction and generally accounts for the differences in risk among the individual utilities by adjusting their capital structures.

EGD's equity thickness was set at 35 percent in 1993. In 1997, the OEB published guidelines for its cost of capital methodology for gas distribution utilities. In the OEB's Draft Guidelines, it stated: "The Board's guidelines [assume] that the base capital structure will remain relatively constant over time and that a full reassessment of [the Company's] capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk."[14]

In 2006, EGD requested an increase in equity thickness from 35 to 38 percent. The OEB noted the trend among Canadian regulators towards thicker equity for utilities, and that EGD's equity percentage may have fallen out of line with its peers. However, since the OEB had recently allowed

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11 *Id.*, at 50.

Union Gas an equity percentage of 36 percent by way of the OEB's approval of a settlement proposal, and Union Gas was perceived to have greater business risk than EGD, EGD's equity determination was effectively bound by Union Gas's negotiated settlement.[12] As a result, the OEB allowed EGD an equity percentage increase of one percentage point to equal that of Union Gas, at 36 percent. EGD and Union Gas' equity thicknesses have remained at 36 percent, including post-amalgamation. Key findings from the OEB regarding the determination of an appropriate equity thickness in EGI, EGD, and Union-specific proceedings, are described below.

EB-2011-0210 (Union Gas)

In EB-2011-0210, the OEB found that Union Gas' equity ratio of 36 percent continued to be appropriate. In its Decision and Order, the OEB reiterated its policy that "for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risks."[13] Further, the OEB described the FRS as requiring that a "fair and reasonable return on capital should:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard)."[14]

The OEB further found that its obligation to determine the equity thickness "is governed by the FRS, which is not an optional legal standard."[15]

EB-2011-0354 (EGD)

In EB-2011-0354, the OEB found that EGD's equity ratio of 36 percent continued to be appropriate. The OEB outlined its then-current policy as follows:

- The OEB had determined that a 40% equity thickness was appropriate for electricity

12 EB-2006,0034, at 63.
13 EB-2011-0210, Decision and Order, at 48.
14 *Id.*, at 49.
15 *Id.*, at 50.

distributors;[16]

- For electricity transmitters, generators, and gas utilities, the equity thickness is determined on a case-by-case basis;[17]

The OEB also provided findings regarding the appropriate time frame over which it would perform its risk assessment, finding that the time frame began with "the time the issue was previously decided in EB-2006-0034."[18] In terms of forward-looking risks, the OEB found that "the relevant future risks are those that are likely to affect Enbridge in the near term," and that "[i]n considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."[19]

In terms of business risks faced by EGD, the OEB found that, compared to 2007, Enbridge had not experienced a significant increase in risk related to declining volumes, system size and complexity, or environmental and technological advancement. Regarding environmental and technological advancement risk, the OEB found "[t]he evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term."[20]

<u>EB-2017-0306 (EGD-Union Gas Amalgamation)</u>

In its amalgamation application, EGD and Union proposed to maintain the equity ratio of the amalgamated entity at 36 percent, which was accepted by the OEB.

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16 EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, at 3.
17 *Ibid*.
18 *Id*., at 7.
19 *Ibid*.
20 *Id*., at 15.

SECTION 4:
CHANGES IN BUSINESS AND FINANCIAL RISKS

There are two fundamental sources of risk for any company, including regulated utilities: business risk and financial risk. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. These risks include operating risk and regulatory risk. Financial risk relates to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

The cost of capital is a forward-looking concept, and utility investors tend to be long-term providers of capital. Consistent with the OEB's methodology for determining the Company's equity ratio, Concentric's analysis begins with an assessment of how the Company's business and financial risk profile has changed since the Company's previous equity thickness proceedings (i.e., 2012). To evaluate changes in Enbridge Gas' business risks, Concentric performed an independent assessment of the Company and its regulatory environment.

Our experience in assessing business and financial risks and the effect on the cost of capital in Ontario and other regulatory jurisdictions informed our review. Our additional experience advising buyers and sellers of regulated distribution utilities, including Canadian utilities, further informs our views on the investor perspective regarding the business risk of these assets. Our evaluation process included research on equity and credit analyst views regarding Enbridge Gas and the regulated gas distribution industry, relevant industry data, other publicly-available materials such as regulatory filings made by Enbridge Gas, the Company's asset management plan, financial reports, and discussions with Enbridge Gas subject matter experts.

Concentric concludes in this section that while the Company's risk level for its regulated operations remains the same in some areas of the business, the overall risk for these operations has significantly increased since 2012, primarily due to the following factors:

- The Energy Transition (described in more detail herein) began in earnest in the last five years. As equity investors and credit rating agencies widely acknowledge, it substantially affects the risk profile of North American gas distribution utilities, including Enbridge Gas.
- An uncertain economic outlook, increased competition from electricity (i.e., the Energy Transition), and the OEB's encouragement of competition from alternative gas suppliers in the Company's service territory have combined to increase the Company's volumetric risk

relative to the Company's previous equity thickness proceedings. Regulatory mechanisms provide short-term insulation, but do not change the long-term challenges facing the Company.

- The Company has experienced a gradual weakening in its debt-related credit metrics (i.e., FFO/Debt and Debt/EBITDA) since 2012. The Company's credit spreads on debt issuances have widened slightly since 2012.
- The complexities of operating gas utilities have increased, putting pressure on the Company regarding project permitting, execution, and cost recovery. Successful management of the associated rate impacts depends on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices.

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

Enbridge Gas Overview

Enbridge Gas is a regulated natural gas distribution utility formed through the amalgamation of EGD and Union Gas in 2019. The Company provides service to approximately 3.8 million residential, commercial, and industrial customers in Ontario, Canada. As of December 31, 2021, the Company's rate base was approximately $14.2 billion ($Canadian).[21] By both measures, Enbridge Gas is among the largest natural gas distribution utilities in North America.

Since the 2019 amalgamation, Enbridge Gas has maintained an issuer credit rating of "A-" from S&P Global Ratings ("S&P") (as of February 1, 2022), and an "A" issuer and unsecured debt rating (with stable trend) (as of October 5, 2021) from DBRS Limited ("DBRS").

[21] EB-2022-0110, Exhibit B, Tab 1, Schedule 1, Page 1 (filed May 31, 2022; updated September 2, 2022).

SECTION 4(a): ENERGY TRANSITION

Introduction

In EB-2011-0354, EGD stated that it faced increased business risk due to environmental policies and laws such as Ontario's Green Energy Act (2009). EGD further submitted that there "is a clear long-term risk that demand for natural gas will decline, as new technologies and energy saving practices take further hold."[22] However, the OEB concluded in 2013 that "Enbridge has not experienced a significant increase in risk since 2007 relating to environmental and technological advancement."[23] Specifically, the OEB found:

> *The evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term. The Board agrees with intervenors that, to the contrary, the policy commitment to cease all coal-fired electricity generation in Ontario is likely to result in more gas-fired electricity generation, which is a benefit to Enbridge. In addition, as discussed under Volumetric Demand Profile, to the extent that DSM initiatives decrease Enbridge's volume, this risk is addressed by the LRAM account. Also, as discussed above, increasing energy efficiency has the effect of strengthening the ongoing competitive position of gas compared to other fuels.*[24]

The situation today is starkly different than at the time of the OEB's above-quoted findings. Within the last five years, and accelerating within the past year, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more renewable fuel sources.[25] As a result, the risk profile of natural gas distribution utilities such as Enbridge Gas has fundamentally changed.

The subsections that follow discuss the evidence that the Energy Transition is already underway, the steps the Company has taken in response to the Energy Transition, and the effects of the Energy Transition on the Company's current risk profile.

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22 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 14.
23 *Id.*, at 15.
24 *Ibid*.
25 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/research-insights/articles/what-is-energy-transition.

1. Evidence of the Energy Transition

a) *Government Policy*

Protecting the environment is an increasing area of focus for federal, provincial, and local governments in both Canada and the U.S. At the federal level, the Trudeau administration pledged to reduce greenhouse gas ("GHG") emissions by 40 to 45 percent (relative to 2005 levels) by 2030,[26] and to achieve net zero emissions by 2050, consistent with the Paris Accord that was signed in 2015.[27] In June 2021, the federal government formalized Mr. Trudeau's pledge by passing the Canadian Net-Zero Emissions Accountability Act, setting into law the commitment to achieve net-zero carbon emissions by 2050. The federal act also mandates the setting of intermediary targets at five-year intervals (2030, 2035, 2040, and 2045) at least a decade in advance of each target, and requires the development of emissions reduction plans for these targets. Further, Prime Minister Trudeau's recent re-election makes it likely that these environmental policies will continue.[28]

Additionally, the Canadian federal government adopted a carbon tax in 2019. The tax is approximately $50 per metric tonne in 2022 and, as summarized in Figure 2, is expected to reach $170 per metric tonne by 2030. All else equal, the increase in the carbon tax means that delivered natural gas prices to Enbridge Gas' customers will also increase, thereby eroding the price advantage of natural gas relative to electricity.

26 CBC News, "Trudeau Pledges to Slash Greenhouse Gas Emissions By At Least 40% by 2030," April 22, 2021, https://www.cbc.ca/news/politics/trudeau-climate-emissions-40-per-cent-1.5997613.

27 S&P Global Market Intelligence, "Biden, Trudeau Agree to Pursue Goal of Net-Zero Emissions by 2050," February 24, 2021, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/biden-trudeau-agree-to-pursue-goal-of-net-zero-emissions-by-2050-62841040.

28 The Conversation, "Canada's Federal Election Made Big Strides for Climate and the Environment," September 30, 2021, https://theconversation.com/canadas-federal-election-made-big-strides-for-climate-and-the-environment-168918.

Figure 2: Canadian Carbon Tax Projections[29]

Year	Carbon Tax ($/tonne)	Cents / Cubic Meter of Natural Gas
2023	$65	12.39
2024	$80	15.25
2025	$95	18.11
2026	$110	20.97
2027	$125	23.83
2028	$140	26.69
2029	$155	29.54
2030	$170	32.40

At the local level, at least 48 municipalities in Ontario have declared climate emergencies, as illustrated in Figure 3.

Figure 3: Municipalities in Ontario with Declared Climate Emergencies

Aurora	Essex	London	Sarnia
Barrie	Goderich	Meaford	St. Catharines
Bracebridge	Greater Sudbury	Middlesex Centre	Stratford
Brampton	Grey Highlands	Milton	Thunder Bay
Brantford	Guelph	Mississauga	Toronto
Burlington	Halton Hills	Niagara-on-the-Lake	Vaughan
Caledon	Halton	Oakville	Waterloo
Cambridge	Hamilton	Ottawa	Waterloo
Chatham-Kent	Kenora	Peel	West Grey
Cobourg	King	Petawawa	Wilmot
Collingwood	Kingston	Peterborough	Windsor
Durham	Kitchener	Prince Edward	Woolwich

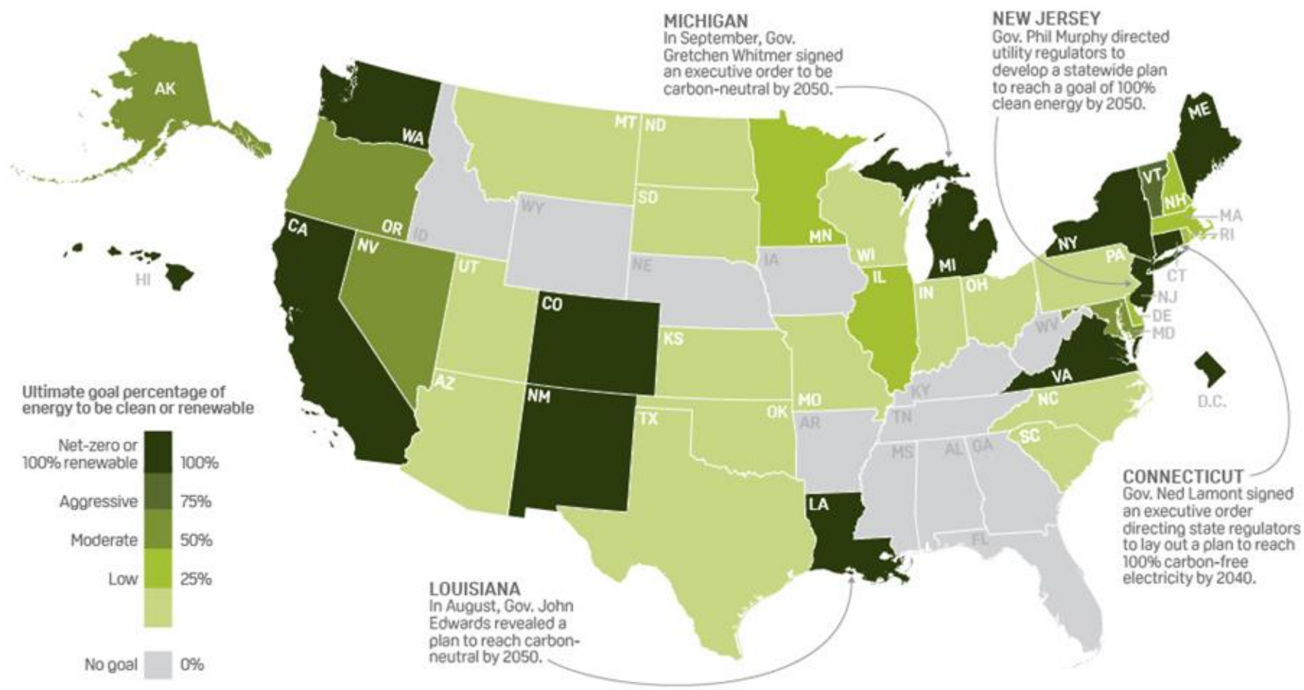
The Energy Transition is accelerating rapidly in the United States as well. President Joe Biden's administration is targeting a 50 percent reduction in GHG emissions relative to 2005 by 2030, and net zero emissions economy-wide by 2050.[30] This effort was reinforced by the August 2022 climate change legislation that was included in the Inflation Reduction Act ("IRA") signed by President Biden.

29 Government of Canada, "Fuel Charge Rates for Listed Provinces and Territories for 2023 to 2030" (https://www.canada.ca/en/department-finance/news/2021/12/fuel-charge-rates-for-listed-provinces-and-territories-for-2023-to-2030.html; accessed September 29, 2022).

30 White House Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies, April 22, 2021, https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

The legislation provides approximately $370 billion in new spending over the next ten years to promote research on low-carbon technologies and new agricultural programs, to provide incentives for electric heat pumps, and to provide tax credits for electric vehicles, among other things. According to analysts, the IRA will result in a 41 percent reduction in U.S. emissions by 2030, compared to 2005 levels. Without the new legislation, emission reductions were only projected at 27 percent by 2030, as compared to the Biden administration's commitment to reduce emissions by 50 percent from 2005 levels by 2030.[31] In addition, as shown in Figure 4, at least a dozen U.S. states have committed to net zero or 100 percent renewable power targets by 2050 or earlier.

Figure 4: United States Renewable Targets[32]



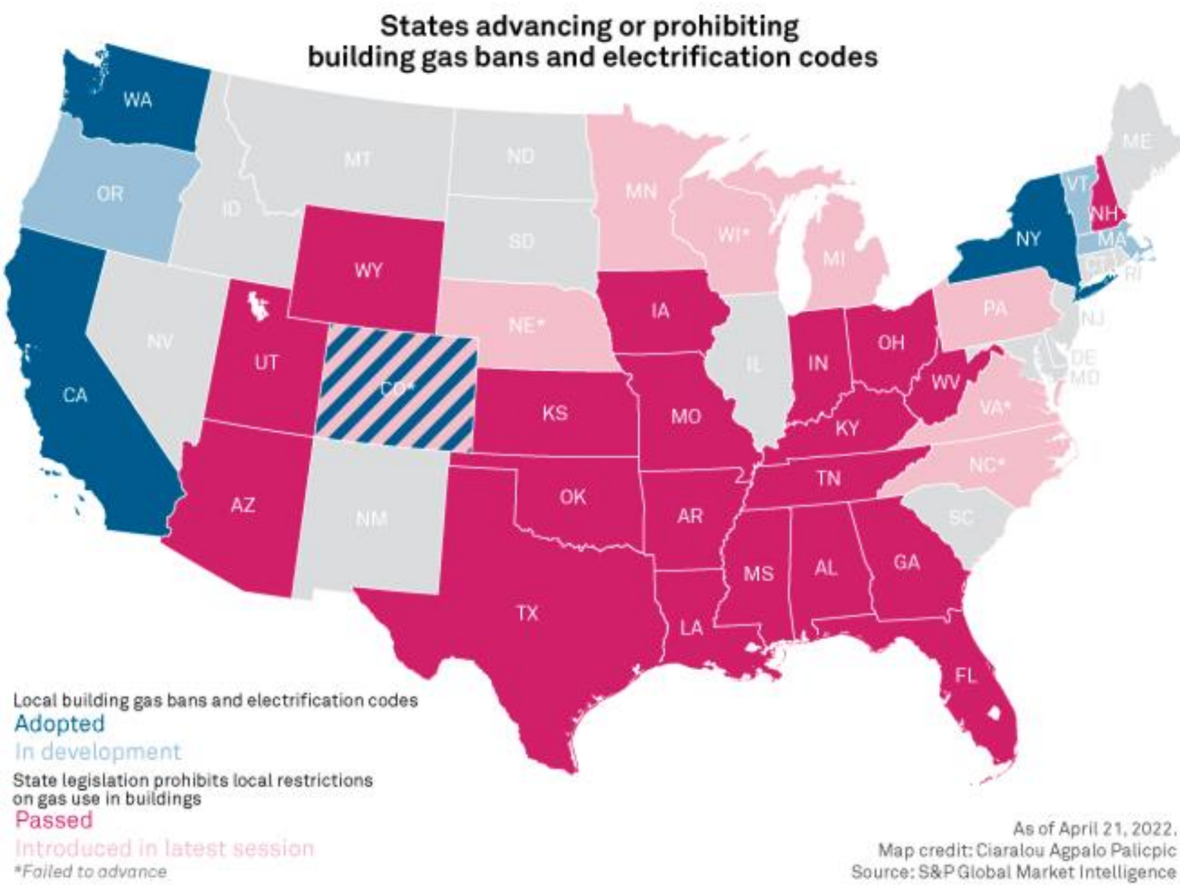
Additionally, restrictions on gas use in buildings have advanced at the state or local level in at least six U.S. states that collectively represent approximately one quarter of gas use in the U.S. These restrictions threaten natural gas customer growth because they generally apply to new buildings, but in some cases, such as Washington and New York, state policymakers have also proposed plans that

[31] Council on Foreign Relations, "What the Historic U.S. Climate Change Bill Gets Right and Gets Wrong," August 17, 2022.

[32] S&P Global Platts, "Commodities 2021: States Racing to Set Goals Towards Net-Zero Emission, 100% Renewable Electricity," December 24, 2020.

would phase gas use out of existing buildings.[33] In juxtaposition to these developments, at least 20 other states have passed laws prohibiting gas bans at the local level. Figure 5 summarizes the various legislative developments regarding building gas bans in the U.S.

Figure 5: Status of Building Gas Bans by State[34]



While the prohibitions on building gas bans in many U.S. states are a positive near-term development for natural gas distribution utilities in some jurisdictions, declining costs and government support for alternatives to gas space heating continue to pressure natural gas' long-term economic viability. As the consultancy the Brattle Group ("Brattle") recently observed:

> *Traditional gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals. Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment*

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33 S&P Capital IQ Pro, "Natural Gas in Transition: High-Stakes Battles Over Gas Use Take Shape," June 7, 2021.

34 S&P Capital IQ Pro (formerly S&P Global Market Intelligence), "Gas Ban Monitor: Building Electrification Evolves as 19 States Prohibit Bans," July 20, 2021.

> *of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector. The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.*[35]

Concentric is not aware of any building gas bans, or prohibitions on such bans, in Ontario. However, as discussed previously, 48 municipalities have already declared climate emergencies in Ontario. Twenty one Ontario communities, including the City of Toronto, are urging the Ontario government to phase out the use of gas-fired electricity generation.[36] In December 2021, the Toronto City Council adopted an ambitious strategy to reduce community wide GHG emission in Toronto to net zero by 2040 – ten years earlier than initially proposed. Toronto's net zero by 2040 target is one of the most ambitious in North America. To reach its targets, the City will use its influence to regulate, advocate and facilitate transformation in five key areas:

- Demonstrate carbon accountability locally and globally, by establishing a carbon budget for its own operations and the community as a whole.
- Accelerate a rapid and significant reduction in natural gas use.
- Establish performance targets for existing buildings across Toronto.
- Increase access to low-carbon transportation options, including walking, biking, public transit and electric vehicles.
- Increase local renewable energy to contribute to a resilient, carbon-free grid.[37]

Further, while not enacted, the provincial government has previously drafted climate change action plans that include the phase-out of gas for home heating by 2030.[38] Additionally, the current Minister of Energy, Todd Smith, requested in 2021 that the Independent Electricity System Operator ("IESO") (1) "evaluate a moratorium on the procurement of new natural gas generating stations in Ontario," and (2) "develop an achievable pathway to phase-out natural gas generation and achieve zero emissions in the electricity system."[39] Then, in August 2022, Mr. Smith accelerated the timeline for an interim report from the IESO, stating that he "asked the IESO to speed up that report back to us so

35 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities to A Decarbonized Future," Part 1 of 3, August 2021, at 9.

36 The Energy Mix, "Toronto City Council Calls for Ontario Gas Phaseout," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

37 https://www.toronto.ca/news/net-zero-by-2040-city-council-adopts-ambitious-climate-strategy/

38 CBC News, "Ontario Government Not Denying Report on Sweeping Climate Change Plan," March 12, 2021, https://www.theenergymix.com/2021/03/12/toronto-city-council-calls-for-ontario-gas-phaseout/.

39 Letter from the Honourable Todd Smith, Minister of Energy, to Lesley Gallinger, President and Chief Executive Officer of the Independent Electricity System Operator, October 7, 2021.

that we can get the information from them as to what the results would be for our grid here in Ontario and whether or not we actually need more natural gas… I don't believe that we do."[40]

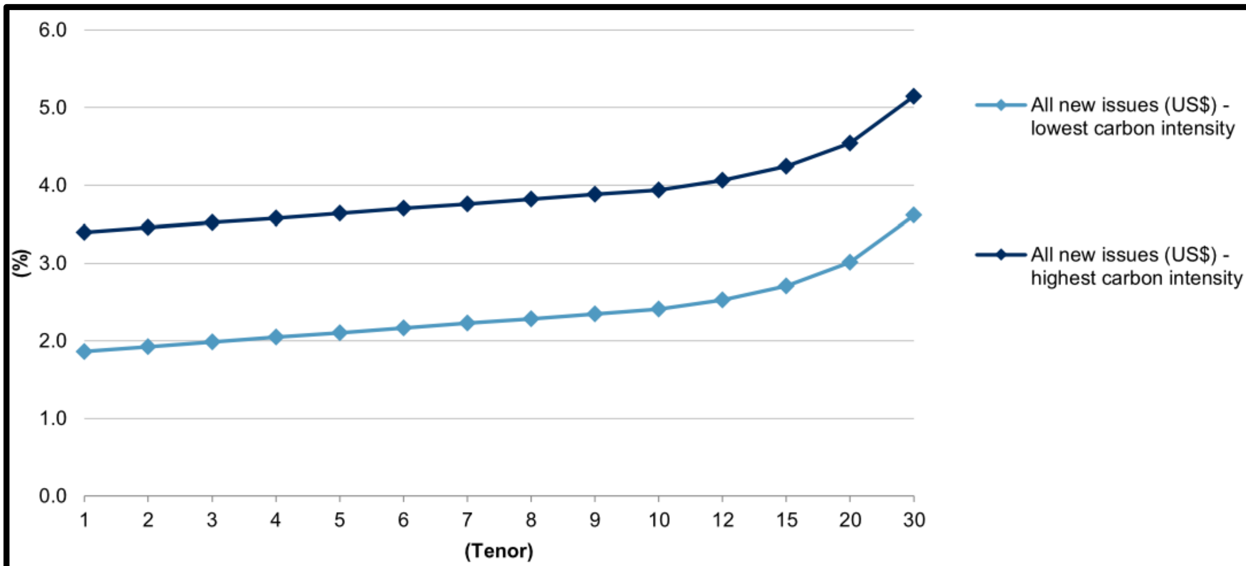
b) Investor Actions

In addition to the governmental developments discussed above, an increasing number of investors have instigated a "capital transition" and are prioritizing environmental, social and governance ("ESG") considerations when making investment decisions. S&P and Moody's have incorporated ESG criteria into their credit rating analyses, 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 its portfolio management; exiting investments that present a high sustainability-related risk, and strengthening its commitment to sustainability and transparency in investment stewardship activities.[41] BlackRock joins investors on a global basis that collectively represent more than $60 trillion in assets under management, including asset managers such as J.P. Morgan, Santander, and Goldman Sachs.[42] Those investors are now pushing utilities to decarbonize by 2035.[43] Six of Canada's largest banks, including the Bank of Montreal, the Canadian Imperial Bank of Commerce, the National Bank of Canada, the Royal Bank of Canada, Scotiabank, and Toronto-Dominion Bank, recently signed on to the Net-Zero Banking Alliance, thereby committing to establishing a variety of sustainability-linked emissions targets.[44] These banks are the primary debt capital providers for EGI. In Ontario specifically, Ontario Teachers' Pension Plan is targeting a 45% reduction in "portfolio" emissions intensity by 2025, a two-thirds decrease by 2030, and net zero by 2050.[45]

40 The Canadian Press, "Ontario energy minister asks for early report exploring a halt to natural gas power generation," August 23, 2022.
41 BlackRock Letter to CEOs, "A Fundamental Reshaping of Finance," January 20, 2020.
42 Climate Action 100+, Investor Signatories, https://www.climateaction100.org/whos-involved/investors/. See also MarketWatch, "World's Largest Asset Manager BlackRock Joins $41 Trillion Climate-Change Investing Pact," January 14, 2020, https://www.marketwatch.com/story/worlds-largest-asset-manager-blackrock-joins-41-trillion-climate-change-investing-pact-2020-01-09.
43 S&P Capital IQ Pro, "Investors With $60 Trillion in Assets Call on Utilities to Decarbonize by 2035," October 20, 2021.
44 https://mcmillan.ca/insights/major-canadian-banks-join-net-zero-banking-alliance-nzba-unpacking-the-initiative-and-net-zero-commitments/.
45 Ontario Teachers' Pension Plan, "Ontario Teachers' Releases Ambitious Interim Net-Zero Targets," September 16, 2021, https://www.otpp.com/news/article/a/ontario-teachers-releases-ambitious-interim-net-zero-targets.

Investor ESG concerns are already affecting capital markets, as illustrated by S&P's analysis of the financing costs of North American oil and gas companies relative to their environmental impact. Specifically, S&P grouped North American energy companies into quartiles based on the carbon intensity of their revenue as measured by the annual metric tons of carbon emissions per million dollars of annual revenue. S&P concluded that it saw "evidence that issuers with lower carbon intensity were able to issue longer-dated debt at lower financing costs than their more carbon-intense peers."[46] Figure 6 provides the yield curves that S&P developed for new debt issuances from the companies in the highest and lowest quartiles of carbon intensity. As shown, issuers in the highest carbon intensity quartile tend to have materially more expensive debt than issuers in the lowest carbon intensity quartile. S&P estimated that differences in debt yields between the highest and lowest carbon intensity issuers exceeded 150 basis points for 10+ year issuances over the period studied.

Figure 6: S&P Estimated North American Energy New Issues Yield Curve: 2019-2021[47]



Source: Refinitiv, S&P Global Trucost, S&P Dow Jones Indices, and S&P Global Ratings. Data from Jan. 1, 2019-May 10, 2021.

[46] S&P Global Ratings, "The Energy Transition: ESG Concerns Are Starting to Present Capital Market Challenges to North American Energy Companies," June 14, 2021, at 4.

[47] *Id.*, at 5.

c) Utility Commitments

Dozens of North American electric and gas utilities that collectively represent hundreds of billions of dollars in market capitalization have established "net-zero" targets of 2050 or earlier, with many interim emission reduction targets announced as well.

Figure 7 summarizes many of the most prominent emissions related commitments by utilities in both the U.S. and Canada.

Figure 7: North American Utility Emissions Commitments[48]

Company	Ticker	Market Cap ($B)	Goal
Duke Energy Corp.	DUK	$81	Net-zero methane from gas utility by 2030; Companywide by 2050
Enbridge, Inc.	ENB	$79	Net-zero GHG emissions by 2050; 35% intensity reduction by 2030
Southern Co.	SO	$69	Net-zero carbon emissions by 2050; 50% by 2030
Dominion Energy Inc.	D	$62	Net-zero for gas operations by 2040; Companywide by 2050
TC Energy Crop	TRP	$58	Net zero GHG emissions by 2050; 30% by 2030
National Grid	NG	$47	Net zero GHG emissions by 2050
Sempra Energy	SRE	$42	SDG&E targeting zero-carbon power by 2045
Xcel Energy Inc.	XEL	$37	100% carbon-free by 2050; 80% carbon-free by 2030
Public Service Enterprise Group Inc.	PEG	$32	Net-zero carbon emissions from power generation by 2050
Eversource Energy	ES	$31	Carbon-neutral companywide by 2030
WEC Energy Group Inc.	WEC	$30	Net-carbon neutral electric generation fleet by 2050
Ontario Power Generation [1]	N/A	$30	Net zero by 2040
Consolidated Edison Inc.	ED	$27	100% clean electricity by 2040
DTE Energy Co.	DTE	$23	Net-zero companywide by 2050
Entergy Corp.	ETR	$22	Net-zero emissions by 2050
Ameren Corp.	AEE	$22	Net-zero carbon emissions across its operations by 2050
Edison International	EIX	$22	Supports state goal of carbon neutrality by 2045
FirstEnergy Corp.	FE	$21	Carbon neutral by 2050
PG&E Corp.	PCG	$21	Commited to meeting California goal of carbon neutrality by 2045
Avangrid Inc.	AGR	$20	Carbon neutral by 2035; Working to reduce methane from gas
CMS Energy Corp.	CMS	$18	Net-zero methane from gas utility by 2030; Electricity by 2040
AES Corp.	AES	$16	Net-zero emissions by 2050
Hydro One	H	$15	Net-zero GHG emissions by 2050; 30% decrease by 2030
Algonquin Power and Utilities	AQN	$12	Net-zero by 2050; 75% renewable generation by 2023
Emera Inc.	EMA	$12	Net-zero CO2 emissions by 2050; 55% decrease by 2025
NRG Energy Inc.	NRG	$10	Net-zero GHG emissions by 2050
Vistra Corp.	VST	$9	Net-zero carbon emissions by 2050
Pinnacle West Capital Corp	PNW	$9	100% carbon-free electricity by 2050
AltaGas Inc.	ALA	$6	Supports DC's goal of carbon neutrality by 2050
Spire, Inc.	SR	$4	Carbon neutral by 2050; 53% methane reduction by 2025
South Jersey Industries, Inc.	SJI	$3	Carbon neutrality by 2040; 70% reduction by 2030
Chesapeake Utilities Corp	CPK	$2	Net-zero direct GHG emissions by 2035
Northwest Natural Gas Company	NWN	$2	Carbon neutral by 2050

A recent update to this survey by S&P Global characterizes the state of the industry as follows:

> Over the past five years, virtually all leading U.S. utilities have gone from business as usual to setting greenhouse gas emissions reduction targets to making net-zero announcements. Twenty-five of the country's 30 largest power and natural gas companies by market cap have

48 S&P Global Market Intelligence, "Path to Net Zero: 70% of Biggest US Utilities Have Deep Decarbonization Targets," December 9, 2020. Supplemented with Concentric research.
[1] Ontario Power Generation is not publicly-traded; therefore, its market capitalization reflects the value of its net property, plant, and equipment as of June 30, 2021.

> set interim carbon reduction milestones, a new survey by S&P Global Commodity Insights shows. Two of those companies, Public Service Enterprise Group Inc. and Eversource Energy, have promised to phase out all their greenhouse gas emissions by 2030, rendering an interim target superfluous.
>
> .....
>
> Three of the nation's 30 largest utilities — CMS Energy, Dominion Energy Inc. and Duke Energy Corp. — this year expanded their climate targets to include all emissions connected with natural gas, including hard-to-measure Scope 3 emissions. Their moves came after pressure from shareholder groups, which insist that U.S. utilities must step up their game to help the world combat climate change."[49]

The utilities industry is responding to both public policy mandates and pressures from shareholders to take aggressive actions to reduce greenhouse gas emissions. Also, according to S&P, "[m]ore than half of global assets under management are now committed to net zero by 2050 through the Net Zero Asset Managers initiative which is part of the Glasgow Financial Alliance for Net Zero (GFANZ)."[50] So even where public policy measures do not require emission reductions, investors are pressuring companies to alter their business profiles.

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[49] S&P Global, "Path to net-zero: Utility execs insist 'we can'," June 9, 2022, (https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-utility-execs-insist-we-can-69901885).

[50] S&P Dow Jones Indices, "S&P Dow Jones Indices and S&P Global Sustainable1 Launch S&P Net Zero 2050 Carbon Budget Index Series," September 8, 2022, (https://www.prnewswire.com/news-releases/sp-dow-jones-indices-and-sp-global-sustainable1-launch-sp-net-zero-2050-carbon-budget-index-series-301620184.html).

d) Regulatory Response

In response to these developments, multiple regulators in the U.S. have opened dockets investigating the role that local gas distribution companies ("LDCs") will play during and after the Energy Transition. For example, in Massachusetts, the Office of the Attorney General ("AGO") petitioned the Department of Public Utilities ("DPU") in June 2020 to "initiate an investigation to assess the future of LDC operations and planning in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ('GHG') emissions by 2050."[51] The AGO acknowledged that "climate policy requirements will have profound impacts on gas distribution system management, operations, and rates. This will require the LDCs to make significant changes to their planning processes and business model."[52] Noting that as "electrification and decarbonization of heating increases, the Commonwealth's natural gas demand and usage from thermal heating requirements will decline substantially and could be near zero by 2050,"[53] the AGO raised several questions, including:

- "Should shareholders pay for the diversification and expansion of the LDC's business operations to meet GHG emission limits?"[54]
- "How much additional LDC investment is prudent in the next 30 years to ensure a safe and reliable gas distribution system, while statewide gas demand declines?"[55]
- "Should the Department [i.e., the DPU,] adjust GSEP [Gas System Enhancement Plan] planning and cost recovery to mitigate against potentially stranded infrastructure investment, as well as operations and maintenance expenses as a result of declining gas demand? Should accelerated depreciation or retirement of older leak prone infrastructure alternatives be considered?"[56]
- "Can the LDCs sustain their current business model as the Commonwealth takes affirmative action to electrify and decarbonize the heating sector? What does the LDC look like in 2030? 2040? 2050?"[57]

Additionally, the Public Utilities Commission of the State of Colorado ("Colorado PUC") opened a proceeding in 2020 to "serve as a repository for presentations, comments, and other materials

51 Massachusetts Docket D.P.U. 20-80, Petition of the Office of the Attorney General, June 4, 2020, at 1.
52 *Id.*, at 2.
53 *Id.*, at 7.
54 *Id.*, at 12.
55 *Id.*, at 13.
56 *Id.*, at 14.
57 *Id.*, at 15-16.

relating to the Commission's general investigation of retail natural gas industry greenhouse gas emissions in light of the statewide greenhouse gas emission reduction goals."[58] The Colorado PUC specifically noted that:

> *Potential changes to the business model or scale of usage are of great consequence to the Commission in ensuring effective regulation of the natural gas sector. The Commission is responsible for regulation of several aspects of the retail natural gas industry in Colorado including rate setting, system safety and integrity riders, demand-side management programs, reliability of service, and gas pipeline safety. This market uncertainty and the relatively short timeline to make significant progress on the statutory greenhouse gas emission reduction goals makes it important for the Commission to obtain more information about potential impacts to utility systems and how those impacts may affect utility investments and the rates utilities charge Colorado customers.*[59]

Regulators in California opened a similar proceeding in January 2020, finding:

> *With respect to past events, several operational issues in Southern California prompt the Commission to reconsider the reliability and compliance standards for gas public utilities. Over the next 25 years, state and municipal laws concerning greenhouse gas emissions will result in the replacement of gas-fueled technologies and, in turn, reduce the demand for natural gas.*
>
> *Thus, in order to ensure safe and reliable natural gas service at just and reasonable rates in California, the Commission will (1) develop and adopt updated reliability standards that reflect the current and prospective operational challenges to gas system operators; (2) determine the regulatory changes necessary to improve the coordination between gas utilities and gas-fired electric generators; and (3) implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.*[60]

The New York Public Service Commission echoed these sentiments in March 2020, stating:

> *Recent developments have challenged conventional approaches to gas system planning. These developments include, but are not limited to, recent and current instances of supply/demand imbalance, the emergence of viable, less-traditional and increasingly*

58 Colorado Proceeding No. 20M-0439G, Decision No. C20-0770, "Decision Opening Repository Proceeding; Scheduling Commissioners' Information Meeting; and Designating Hearing Commissioner," Adopted October 7, 2020, at 1.

59 *Id.*, at 2-3.

60 California Docket R.20-01-007, "Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning," January 16, 2020.

> *cleaner alternative solutions for demand and supply, the controversy and uncertainty associated with major gas infrastructure decisions, and the CLCPA's establishment of state policy directions. All the while, continued investment in gas infrastructure has significant long term financial implications for customers. The current approach to gas system planning poses risks of incomplete alignment with CLCPA, sub-optimal consideration of alternatives and timeframe, increased risk and cost to consumers, and unsatisfactory provision of service and solutions for those same consumers. To align with these policies and to recognize the emergence of potentially viable alternatives to gas infrastructure, gas planning must explicitly take account of the likely useful life of all alternatives, and of the resulting cost and risk implications.*[61]

Of course, the OEB is not bound by the findings of utility regulators in Massachusetts, Colorado, California, or New York. However, these proceedings illuminate the degree to which the operating environment for gas distribution utilities has changed. Within the last two years, multiple regulators have determined that it is necessary to examine the future of gas utilities. Further, these proceedings illustrate the degree to which the Energy Transition affects gas utilities' business risks today, as investors must consider that the long-term prospects of the industry have changed. Even if these impacts take years to unfold, investors take these factors into account today. One sign of this development is the significant upward shift in betas for gas utilities (electrics are also affected), as discussed in a subsequent section.

2. Enbridge Developments

EGI, as a natural gas distributor, has been and will continue to be affected by the Energy Transition. In fact, the Company has already taken a variety of steps to position itself in response to ESG-focused government policies and investors. For example, in November 2020, EGI's parent company, Enbridge Inc. ("Enbridge") committed to achieving net zero GHG emissions by 2050, with an interim target of reducing the intensity of its GHG emissions by 35% relative to 2018 levels by 2030.[62] Beginning in 2021, Enbridge's executive and staff compensation is tied to the Company's progress towards its emissions targets.[63]

Further, the Company's access to capital is becoming increasingly intertwined with its ability to meet ESG goals. In February 2021, Enbridge entered a three-year syndicated Sustainability Linked Credit Facility for $1.0 billion, which allows Enbridge to reduce its borrowing costs if it achieves certain ESG

61 New York Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding, March 19, 2020, at 6-7.
62 Enbridge Inc., "Net Zero by 2050: Pathways to Reducing Our Emissions," at 2.
63 *Id.*, at 11.

goals.[64] Enbridge was also among the first companies in North America to issue a Sustainability-Linked Bond ("SLB") with a $1.0 billion, 12-year term 2.50% issuance in June 2021.[65] Enbridge estimated that this bond issuance received a 5-basis point "greenium" (i.e., discount relative to the estimated interest rate of a regular debt issuance from Enbridge at that time) because the interest rate was linked to Enbridge's ability to achieve certain emissions and inclusion targets.[66] However, Concentric notes that this SLB issuance includes asymmetrical risks and rewards. While Enbridge benefits from the estimated 5-basis point "greenium," the SLB issuance also includes a 50-basis point penalty if Enbridge fails to meet the GHG emission reduction milestones.[67]

Enbridge issued a second SLB in September 2021 and estimated that the "greenium" doubled to 10-basis points.[68] Bond analysts have noted that such premiums are increasingly common among green bond issuances as investor demand far outpaces supply.[69] Average oversubscription on green bonds issued in U.S. dollars was 4.7x in the first half of 2021, as compared to just 2.5x for equivalent non-green debt issuances.[70]

Equity investors have taken note of Enbridge's ESG efforts. For example, one CIBC analyst noted that the Company's efforts may reduce the "ESG discount" on its stock:

> *While it will take some time to develop, we think meaningful participation in energy transition projects could be a key catalyst to reducing the ESG discount in energy infrastructure share valuations. To this end the company announced an MOU for a carbon capture development partnership, Cross Carbon Ventures (CCV), with Svante Inc, Cross River Infrastructure Partners and OTS Ltd to explore carbon capture projects. This is one of many areas the company is looking at in order to invest in the energy transition, in addition to the existing renewable energy business, and RNG. It is also continuing the development of the solar self-power program in both Liquids Pipelines and Gas Transmission, with three facilities in operation and four more under construction.*[71]

In July 2021, the OEB issued an order on the Company's Integrated Resource Planning ("IRP") proposal. Generally, the IRP provides a planning process that enables the Company to evaluate,

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64 Enbridge Inc., "Enbridge Reports Strong 2020 Financial Results," February 12, 2021, https://www.enbridge.com/media-center/news/details?id=123663.
65 S&P Capital IQ Pro, "Enbridge Closes $1B Sustainability-Linked Bond Financing," June 29, 2021.
66 Bloomberg News, "Enbridge Doubles 'Greenium' with Canadian SLB Sale," September 17, 2021.
67 Enbridge Inc., Form 424B5 Prospectus Supplement, June 24, 2021, at 2.
68 Bloomberg News, "Enbridge Doubles 'Greenium' with Canadian SLB Sale," September 17, 2021.
69 S&P Capital IQ Pro, "Green Bond 'Greenium' is Evident Globally, Especially Strong for US Dollar Debt," September 15, 2021.
70 *Ibid*.
71 CIBC Equity Research, "Enbridge Inc: Solid Quarter and Capital Outlook Building," August 2, 2021.

compare and implement supply-side (e.g., compressed natural gas, renewable natural gas, peaking supply) and demand-side (e.g., energy efficiency and demand response) options for meeting system energy needs. However, the OEB also identified three specific risks that accompany the first-generation IRP framework it approved:

- Plan Accuracy: The OEB noted that the IRP assessment process "should result in more prudent and effective integrated resource system planning,"[72] which should reduce the risk that it does not accurately identify superior alternatives to facility projects. However, the OEB also noted that it "retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives, and Enbridge Gas acknowledged this possibility."[73]

- Success of IRP Plan Implementation: The OEB indicated that Enbridge Gas "may be at risk for recovery of some portion of IRP investments that are deemed imprudent," and that "there may be a greater degree of performance and cost risk associated with IRPAs [IRP alternatives] and IRP Plans in comparison with facility projects" because the Company has "less experience in addressing system constraints using IRPAs like geotargeted DSM or demand response, and these IRPAs depend on consumer behaviour for success."[74]

- Stranded Assets: The OEB found that the "risk of stranded assets is a concern for both infrastructure builds and for IRPAs. The OEB has limited experience with the treatment of stranded assets. The examination of the treatment of stranding of assets in other jurisdictions and the findings of the Technical Working Group on this topic might help provide a better understanding of stranded assets and options to allocate the costs between Enbridge Gas and its customers."[75]

Absent the Energy Transition, EGI would not be subject to these same risks, which are only partly mitigated by the OEB's approval of the Company's plans.

3. Viability of Alternatives

Achieving net zero GHG emissions by any date is a tremendous challenge for any natural gas distribution utility, Enbridge Gas included. There are two commonly identified fuel alternatives for gas distribution utilities to comply with net zero targets: hydrogen and renewable natural gas

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72 EB-2020-0091, Decision and Order, July 22, 2021, at 61.
73 *Ibid*.
74 *Ibid*.
75 *Id*., at 62.

("RNG"). However, pursuing those pathways carries risk from an investor's perspective. This section discusses the various operational, technical, and financial concerns that investors have noted with large-scale moves towards hydrogen and RNG.

a) Hydrogen

The Company recently proposed, and the OEB recently approved, a pilot project involving the injection of a controlled quantity of hydrogen into an isolated portion of its distribution system in Markham, Ontario. Enbridge Gas undertook the project, referred to as the Low Carbon Energy Project ("LCEP"), as a first step in gaining experience with hydrogen injection. Successful implementation of the LCEP will allow the Company to pursue additional, larger scale hydrogen blending in other portions of its system.[76] Three cost categories were identified in the LCEP proceeding:

- Consumption Impact: The heating value of hydrogen is approximately one third that of natural gas. Therefore, customers receiving blended gas under the LCEP pilot program would consume more gas than if they received natural gas, all else equal.[77] The Company bills volumetrically; therefore, increased consumption would result in increased bills for customers.
- Facilities Impact: The Company incurred costs isolating a portion of its distribution system and constructing a hydrogen blending station.[78]
- Commodity Impact: The price of hydrogen may differ from the price of traditional natural gas. In the case of the LCEP pilot program, the Company acquired hydrogen from 2562961 Ontario Ltd for a price that tracked the market price of traditional natural gas.[79]

As a pilot program, the LCEP is in its early stages, and the Company is providing updates regarding its experience with the project as part of this rebasing application. The Company has also committed to following up with the OEB and other interested parties after five years of actual experience regarding several aspects of the project, including its costs, stakeholder communications, and recommended next steps.[80] Therefore, it is premature to draw conclusions regarding the viability of

76 EB-2019-0294, Leave to Construct Application: Low Carbon Energy Project, December 20, 2019, at 1-4.
77 EB-2019-0294, Decision and Order, October 29, 2020, at 21.
78 *Ibid*.
79 *Ibid*.
80 *Id.*, at 12-14.

hydrogen in the Company's system on a broader scale at this time because the results of the LCEP pilot program are currently uncertain.

However, it is precisely that uncertainty that creates risk for investors. Further, it is an uncertainty that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012). At that time, whether natural gas distribution utilities could remake their systems to support hydrogen was not a topic of question. In contrast, today, analysts such as Wells Fargo are noting:

> *Even with the steps being taken to decarbonize, it is yet to be seen whether the LDC decarbonization story will ultimately resonate with ESG-minded investors. We expect the answer will be influenced by (1) the pace at which LDCs clean-up the gas molecules and reduce overall emissions, which likely requires technological advancements to drive down the costs of RNG and hydrogen and (2) the level of local policy support.*[81]

Credit rating agencies are cautious regarding the near-term prospects for hydrogen. For example, S&P noted that hydrogen "faces many hurdles" and that a "truly hydrogen-based economy, in which hydrogen, not gas, is used to heat buildings and balance the power grid, for example, therefore appears out of reach, at least before 2030."[82] S&P elaborated:

> *S&P Global Ratings believes hydrogen can push the energy transition forward, but this would require coordinated policy, lower hydrogen production costs, and massive growth of renewables. Energy transitions typically take decades. A Hydrogen Council report suggests that hydrogen could account for 15% of global primary energy supply by 2050. Yet the huge cost of producing it is a potential stumbling block. It's more likely that hydrogen developments this decade will be for the production of commercial transport vehicles, assuming fuel-cell costs decline.*[83]

S&P continued:

> *Hydrogen-based heating in buildings, if supported by policy, may likely only be realized well past 2030. Hydrogen boilers or fuel cells can be a cost-competitive low-carbon fuel alternative to heat pumps, at an all-in cost of $4/kg-$5/kg. However, we currently see many hurdles. First, electric heat pumps are already an available cost-competitive option, and are easier to install, not least for new buildings. Second, switching to hydrogen-based boilers requires a major overhaul of the gas network infrastructure. Upgrading grids to allow for hydrogen distribution would require a concurrent rollout of hydrogen boilers (or fuel cells) to all consumers affected by the switch from gas. A prerequisite is a new hydrogen transmission network to which to connect, since many*

[81] Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 4.
[82] S&P Global Ratings, "How Hydrogen Can Fuel The Energy Transition," November 19, 2020, at 1 and 3.
[83] *Id.*, at 1.

> *applications would still rely on gas for decades to come. Affordability is a key consideration because both hydrogen and fuel cells are 1.5x-2.5x more expensive than conventional gas-based household heating, at least in Northern Europe according to a Hydrogen Council report (January 2020).*[84]

Further, panelists convened by Columbia University's Center on Global Energy Policy noted that modifying gas pipelines to carry hydrogen has "generated concern among climate activists" due to fears that hydrogen will prolong fossil fuel use.[85] The panelists indicated that these concerns may mean that operators "seeking to build or adapt infrastructure to carry hydrogen and other low-carbon fuels may face challenges accessing capital."[86]

Therefore, we conclude that while hydrogen may offer a potential pathway for the Company through the Energy Transition, investors perceive significant risk to that pathway because of its operational, technical, and financial challenges.

b) Renewable Natural Gas

Like hydrogen, RNG may offer Enbridge Gas a pathway through the Energy Transition. Another large Canadian natural gas distribution utility, FortisBC Energy Inc. ("FEI"), recently proposed providing all new residential customers with 100 percent RNG in an effort to comply with strict municipal building codes.[87] As part of its application, FEI noted that "federal, provincial and municipal regulations and policies focused on reducing GHG emissions threaten the long-term viability of the gas delivery system."[88]

Concentric is unable to draw conclusions regarding the long-term viability of RNG at this time. However, academics have noted a variety of financial, technical, and other barriers to widespread adoption of RNG. For example, one California study found that "relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough."[89] The study went on to conclude that, after factoring in the more expensive forms of gas, "the commodity cost of blended pipeline gas is more than four to seven times that of

84 S&P Global Ratings, "How Hydrogen Can Fuel The Energy Transition," November 19, 2020, at 10.
85 S&P Capital IQ Pro, "Financing of Hydrogen, Low-Carbon Fuel Pipelines Faces Hurdles in ESG Era," October 4, 2021.
86 *Ibid*.
87 British Columbia Utilities Commission, Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program, Exhibit B-11, filed December 17, 2021, at 1-2.
88 *Id*., at 1.
89 California Energy Commission, Energy Research and Development Division, "The Challenge of Retail Gas in California's Low-Carbon Future," April 2020, at 69.

natural gas today."[90] Another California study noted that "RNG faces large technical obstacles."[91] A study conducted by Washington State University's Energy Program indicated that "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption."[92] Oregon's Department of Energy identified 13 barriers to using RNG to reduce GHG emissions, including financial barriers (i.e., difficulties attracting capital), information barriers (i.e., due to unfamiliarity with the technology), market barriers (i.e., lack of vehicles and infrastructure), and policy barriers (i.e., Oregon-specific rules and statutes impeding RNG development).[93]

These preliminary studies regarding the viability of RNG do not necessarily mean that RNG is not a viable long-term solution. However, from an investor's perspective, pursuing such an uncertain pathway intrinsically carries risk. Further, as with the hydrogen discussion above, it is a risk that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012).

4. Risk Implications

The Energy Transition substantially affects nearly every aspect of the Company's business, from its growth prospects, to the capital projects it pursues, to its fundamental ability to offer investors the opportunity to earn a fair return on, and of, invested capital. Even though the Energy Transition will play out over many decades, it is now underway and it is materially increasing the Company's risk profile because of the long expected lives of most natural gas utility investments. For example, as Brattle recently noted:

> *The transition will affect gas companies' growth opportunities, cost recovery, and capital attraction. In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability. Utilities will need to recover their costs from a changing – and possibly shrinking – customer base. With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks. Heightened perceptions of business risk are increasing financing costs for gas utilities.*[94]

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90 *Ibid*.
91 *Id*., at 33.
92 Washington State University Energy Program, "Promoting Renewable Natural Gas in Washington State: A Report to the Washington State Legislature," December 2018, at 1.
93 Oregon Department of Energy, "Biogas and Renewable Natural Gas Inventory SB334 (2017): 2018 Report to the Oregon Legislature," September 2018, at 43-45.
94 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

Similarly, Moody's observed:

> *Although natural gas transportation and distribution companies continue to provide generally safe, reliable service while reducing emissions, there are ESG reputational risks associated with any hydrocarbon-based business, including financial governance policy risks around a higher cost of capital and lower asset returns over a multi-decade time horizon. Events like the August 2020 Baltimore explosion exact heavy social costs related to customer relations and public health and safety. Financial risks also stem from the likelihood of construction delays and greenfield project budget overruns, potential cancellations, regulatory fines and penalties for accidents, increasing debt obligations associated with gas infrastructure expansion and potential write-offs of stranded assets as the carbon transition progresses.*[95]

McKinsey examined the future for gas utilities under four alternative scenarios, and concluded:

> *These four scenarios, then, envision a wide range of outcomes. What's notable is that in three of them, natural-gas demand declines substantially. The only scenario with stable demand is the one in which renewable natural gas is developed—and this is by no means a sure thing. Clearly, gas LDCs need to prepare.*[96]

The sub-sections below discuss several specific ways in which the Company's risk profile has changed because of the Energy Transition.

a) Volumetric Risk

The opposition to natural gas threatens the Company's sales volumes through franchise renewal challenges, potential net-zero mandates, and increasingly stringent building codes or bans on new gas hook-ups. The Company has deferral and variance accounts that provide a degree of short-term insulation from this risk (insulation that will improve if the Company's SFV rate design proposal is adopted). However, in the long-term, investors are concerned that increasing costs recovered over declining volumes may create a "death spiral" scenario. As Brattle notes:

> *As states pursue degasification policies and homes convert to electric heating, utilities risk losing customers and load. Nationally, electric heating is outpacing gas heating adoption. Technology mandates and policy further accelerate the problem. Utilities will likely continue investing in their existing system for safety and reliability but need to*

95 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 2.

96 McKinsey & Company, "Are US gas utilities nearing the end of their golden age?" September 2018, (https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/are-us-gas-utilities-nearing-the-end-of-their-golden-age).

recover those costs from a shrinking customer base. This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification. Up to $150–180 billion of gas distribution assets could be underrecovered as a result of the transition. This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.[97]

Brattle also observes that the "transition will not occur at the same pace or magnitude across customer classes, which compounds cost recovery risks."[98]

Therefore, as discussed more fully in the volumetric risk section below, we conclude that the Energy Transition increases the Company's volumetric risk.

b) *Operational Risk*

Increasing opposition to natural gas makes it more difficult, costly, and time-intensive for natural gas distribution utilities such as the Company to construct and permit new facilities. Depending on the extent of this opposition, shareholders may bear increasing amounts of operational risks or cost overruns as critical infrastructure projects are delayed. As Moody's notes:

Long-term challenges to natural gas infrastructure are increasing. Natural gas is increasingly being called into question over environmental and greenhouse gas (GHG) emissions. Permitting difficulties related to new pipelines, local government mandates favoring electrification and state carbon reduction commitments raise operating risks and cost of capital.[99]

This increasing opposition represents a marked change from the operating environment in 2012 (i.e., the Company's previous equity thickness proceedings). In 2020, the New York Times noted that oil and gas pipelines are "being challenged as never before as protests spread, economics shift, environmentalists mount increasingly sophisticated legal attacks and more states seek to reduce their use of fossil fuels to address climate change."[100] Setbacks experienced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline were specifically cited as evidence that heightened opposition "represents a break from the past decade, when energy companies laid down tens of thousands of miles of new pipelines."[101] It was further noted that, even

97 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.
98 *Id*., at 15.
99 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.
100 New York Times, "Is This the End of New Pipelines?" July 8, 2020, https://www.nytimes.com/2020/07/08/climate/dakota-access-keystone-atlantic-pipelines.html.
101 *Ibid*.

when projects are successful, the increased opposition results in costly delays. In 2009, gas pipelines took an average of 386 days to receive federal approval to commence construction. That increased to 587 days in 2018.[102] Joan Dreskin, chief counsel to the Interstate Natural Gas Association of America, added that "[b]uilding energy infrastructure today is certainly more challenging that it was five, 10, or 15 years ago."[103] Brandon Barnes, an analyst at Bloomberg Intelligence, opined that the "Dakota Access and Atlantic Coast pipes encapsulate the last few years of a trend we've watched: the dramatic expansion of using regulatory obligations to hurt infrastructure projects in the courts."[104]

While the New York Times specifically highlighted difficulties faced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline, Moody's identified four additional examples (for a total of seven) of legal challenges to pipeline development in 2020, as summarized in Figure 8.

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102 *Ibid*.

103 Reuters, "End Of An Era? Series of U.S. Setbacks Bodes Ill For Big Oil, Gas Pipeline Projects," July 8, 2020, https://www.reuters.com/article/us-usa-pipelines/end-of-an-era-series-of-u-s-setbacks-bodes-ill-for-big-oil-gas-pipeline-projects-idUSKBN2491M5

104 *Ibid*.

Figure 8: Moody's List of Recently Derailed or At-Risk Pipeline Investments[105]

Pipeline	Date	Description of Event
PennEast Pipeline	2/20/2020 (*At Risk*)	PennEast filed an appeal with the Supreme Court of the US, challenging a lower-court ruling that prevents the project from condemning New Jersey state land for pipeline construction.
Constitution Project	2/24/2020 (*Cancelled*)	Williams Companies, Inc. (Baa3 stable) and partners halted investment in the proposed pipeline, citing risk adjusted return prospects no longer supported development.
Frontier Oil Sands Project	2/24/2020 (*Cancelled*)	Teck Resources Limited (Baa3 stable) withdrew its regulatory application for the Frontier oil sands project in Alberta, Canada due to the broader Canadian national discussion on energy development, indigenous reconciliation and climate change. This resulted in a C$1.1 billion write down for Teck.
Keystone XL	3/31/2020 (*At Risk*)	Negative outlook for TransCanada Pipelines Limited (Baa1 negative) reflects the very high level of execution risk related to environmental, social and governance factors associated with the Keystone XL pipeline project, which parent TC Energy Corporation (Baa2 negative) has decided to move forward on.
Northeast Supply Enhancement Project	5/14/2020 (*Withdrawn*)	The New York State Department of Environmental Conservation denies authorization of a water permit to Williams Companies, Inc.'s (Baa3 stable) NESE natural gas pipeline, due to the project's failure to meet water quality standards.
Atlantic Coast Pipeline	7/5/2020 (*Cancelled*)	Atlantic Coast Pipeline canceled, resulting in an approximate $4.8 billion write-off for Dominion Energy Inc. (Baa2 stable) and Duke Energy Corporation (Baa1 stable).
Mountain Valley Pipeline	9/2020 (*At Risk*)	Received re-authorizations for two environmental permits (i.e., stream crossing and biological opinion). MVP is seeking additional federal approval to restart construction that has been halted for about one year. We estimate that the pipeline is nearly three years behind schedule and is roughly $2.0 billion over-budget.

Further, subsequent to the Moody's report, the U.S Circuit Court of Appeals for the D.C District of Columbia vacated a permit order for the 65-mile Spire STL Pipeline. The Court ruled that the Federal Energy Regulatory Commission ("FERC") did not seriously consider arguments that challenged the

105 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 3.

need for the project. FERC had authorized the interstate pipeline in 2018 and construction began in 2019.[106]

While the increase in regulatory and permitting challenges is most pronounced for natural gas and oil pipelines, natural gas distribution utilities are affected as well. For example, National Grid, one of the largest LDCs in the Northeast, recently noted:

> *Despite the steps taken by National Grid to implement the Distributed Infrastructure Solution, the solution faces risks to successful implementation. The distributed infrastructure projects face permitting delays and the risk of not obtaining needed regulatory approvals. The incremental demand-side programs face implementation risks in terms of uncertainty of regulatory approval and funding and uncertainty of meeting targets given the ambitious levels of these programs' demand reduction targets, and the unpredictable nature of customer participation.*
>
> *In particular, while only a few permits remain for the LNG Vaporization Project, the Company has experienced substantial delays in obtaining those permits and the LNG Vaporization Project is key to being able to solve for the Demand-Supply Gap in the near future. Similarly, the ExC project, which Iroquois submitted to FERC in January 2020, is still awaiting approval after a year and a half, and Iroquois is now not expected to ascertain whether it will receive all necessary permits and approvals until 2022. With the implementation lags and other risks inherent in achieving the savings under the DSM programs and the still evolving external work around Net Zero, it is critically important that these distributed infrastructure projects move forward as quickly as possible to meet the growing demands of Downstate NY.*[107]

Enbridge Gas has not been immune to the industry-wide trend of increased opposition to and scrutiny of natural gas distribution projects. For example:

- On November 1, 2019, the Company filed a leave to construct application to construct approximately 10.2 kilometers of natural gas transmission pipeline and associated facilities in the City of Hamilton.[108] While Enbridge Gas ultimately withdrew its application, over a dozen parties intervened in the proceeding, issuing the Company over 800 interrogatories.
- On March 2, 2021, the Company filed a leave to construct application to replace approximately 19.8 kilometers of natural gas pipeline and associated facilities in the City of

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106 S&P Capital IQ, "DC Circuit Knock down FERC certificate for Spire STL gas pipeline," June 22, 2021.
107 National Grid, "Natural Gas Long-Term Capacity – Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")," June 2021, at 18.
108 EB-2019-0159, Decision on Issues List, March 6, 2020.

Ottawa to address integrity issues.[109] Energy Probe Research Foundation, Environmental Defence Canada Inc., Federation of Rental Housing Providers of Ontario, Industrial Gas Users Association, Pollution Probe, School Energy Coalition, and the City of Ottawa were granted intervenor status. Many of these intervenors recommended that the OEB reject EGI's application. For example, the City of Ottawa noted that, in "the current state of flux," rejecting EGI's proposal "would avoid a large investment which may not be required as events around the energy transition unfold."[110] Pollution Probe was even more definitive, stating "[e]very time a new pipeline is built it increases the likelihood for stranded assets and the time to consider those issue [sic] and risk are during this Leave to Construct proceeding. It is no longer acceptable for excess pipelines to be built with the thought that they will eventually be used by future customers and load growth. Those days are gone under a Net Zero future."[111] In May 2022, the OEB rejected the application, citing concerns that EGI had not demonstrated that replacement of this segment of pipeline was necessary or whether other alternatives might be more economical and cost effective. The OEB's decision specifically highlighted the City of Ottawa's position that "… provided that integrity issues are not an immediate significant concern," the proposed St. Laurent replacement project is not consistent with the overall strategic direction the City is taking in its Energy Evolution policy.[112]

- On September 10, 2021, the Company filed a leave to construct application to construct a natural gas pipeline and associated facilities in the Municipality of Greenstone (the "Greenstone Pipeline Project").[113] While the Company estimated the costs of the Greenstone Pipeline Project to be approximately $25.8 million, offsetting those costs was a contribution in aid of construction of approximately $20.3 million from Greenstone Gold Mine LP.[114] Nonetheless, the Greenstone Pipeline Project faced significant opposition from intervenors such as Pollution Probe and Environmental Defence Canada.

- On March 21, 2022 and June 10, 2022, Enbridge Gas filed leave to construct applications for the Dawn – Corunna Replacement Project[115] and the Panhandle Regional Expansion

[109] EB-2020-0293, Staff Submission, March 24, 2022, at 1.
[110] EB-2020-0293, City of Ottawa Letter Summation, March 24, 2022, at 3.
[111] EB-2020-0293, Pollution Probe Argument, March 24, 2022, at 3.
[112] EB-2020-0293, Decision and Order, May 3, 2022, at 13.
[113] EB-2021-0205, Decision and Order, March 17, 2022, at 1.
[114] *Id.*, at 8.
[115] EB-2022-0086.

Project,[116] respectively. Intervenors have challenged those projects, in part, on concerns about long-lived assets becoming stranded because of the declining use of fossil fuels, including natural gas.[117]

The above-referenced leave to construct applications are individual data points and do not represent a comprehensive review of all of the Company's filings since 2012. However, they do serve as case studies illustrating that the Company's experience is consistent with the broader natural gas industry. Thus, we conclude that the Energy Transition has significantly increased the Company's operational risk by increasing the possibility that it will face challenges and delays in siting, permitting, and constructing facilities.

c) *Stranded Asset Risk*

Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. In fact, the OEB recently acknowledged the risk of stranded assets when evaluating the Company's IRP proposal.[118]

The potential for stranded assets was not a material concern for the Company in 2012 (i.e., the time of its previous equity thickness proceedings). As S&P notes, "[s]tranded costs have not up until now been an issue for gas local distribution companies."[119] S&P observes, however, that concerns about stranded assets have spiked recently:

> *While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects*

116 EB-2022-0157.

117 See, e.g., EB-2022-0088, Pollution Probe Submission, September 23, 2022, at 4; and Environmental Defence Submission, at 2-3. See also, e.g., EB-2022-0157, Interrogatories of Environmental Defence (September 1, 2022), at 4-6.

118 EB-2020-0091, Decision and Order, July 22, 2021, at 62.

119 S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

> *has declined in recent years, the specter of stranded assets did not really emerge for existing gas pipelines and the gas LDCs until recently when the zero-carbon movement picked up steam.*[120]

S&P concludes that "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond." [121]

Investors are acutely aware of the increase in stranded asset risk and expect utilities to work with their regulators to mitigate this risk. For example, as Moody's notes:

> *Supportive regulation likely to help companies avoid stranded asset risk. State regulators and utilities will likely collaborate to avoid stranded asset risk as exposure to such risks increases. Adjusting the useful life of assets, accelerating depreciation rates of existing assets and securitizing the asset value of at-risk property, plant and equipment help ensure full investment recovery and support long term utility credit quality.*[122]

Like Moody's, Concentric expects that the OEB will approve measures to mitigate the Company's stranded asset risk, up to and potentially including the acceleration of depreciation rates as appropriate. However, we note that this is a "downside-only" area for the Company. In other words, while regulatory changes (e.g., the acceleration of depreciation rates) may improve the Company's prospects of recovering its investment, there remains a chance that investors are not able to earn a full "return of" their invested capital. There is no scenario under which investors face less risk than before the advent of the Energy Transition. Further, all else equal, accelerating depreciation rates will increase rate pressure for customers, rendering natural gas less competitive against alternative energy sources, mainly electricity. Therefore, while we expect the OEB and the Company will work together to mitigate stranded asset risks, we conclude that stranded asset risks have increased since 2012.

d) *Going Concern*

Depending on the specific pathways ultimately taken by the Canadian federal government and the province of Ontario, the Company may no longer be able to engage in the provision of its main business enterprise: the distribution of natural gas.

120 *Ibid*.
121 *Id*., at 11.
122 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

Consultants for the Attorney General of Rhode Island, in recommending that the State of Rhode Island Division of Public Utilities and Carriers condition the sale of Narragansett Electric (the largest electric and gas LDC in Rhode Island) on the limitation of capital expenditures, summarized the "going concern" issue as follows:

> *[L]egal and societal pressures are building to substantially reduce fossil fuel consumption. Moreover, policymakers are becoming increasingly concerned about methane emission in both gas production and distribution activities. In addition, the costs associated with replacing obsolescent natural gas distribution systems have increased substantially over the past decade, as many distribution utilities have accelerated their system replacement efforts. Finally, electric alternatives to natural gas heating (e.g., "mini-splits") are becoming more efficient and cost competitive. The economic risks to gas distribution service are both environmental and economic. Having a monopoly on natural gas distribution service does not insulate the utility from competition with alternative energy sources.* ***In that context, it is not clear that natural gas distribution systems serving residential and smaller commercial customers have a long-term future****.*[123]

The future for the gas distribution business is far from certain, and the Company is taking a variety of steps to position itself in response to the Energy Transition. As noted above, the Energy Transition creates both risks and opportunities for gas utilities such Enbridge Gas. For example, the Company's previously-discussed IRP may provide rate base IRPAs. However, there remains substantial risk from an investor's perspective. For example, Wells Fargo stated:

> *We had many conversations with investors this year regarding gas utilities place (or lack thereof) in a decarbonizing world and, from a similar but different angle, how the LDCs fit into the ESG picture. This conversation started in 2019, which saw the advent of the local ban on new gas hookups. The discussion heated up in the throes of the pandemic as (1) the LDC underperformance itself led investors to seek out explanations as to why with terminal value concerns coming up as one potential reason and (2) the green theme gained momentum with clean energy plays, such as NEE and ORSTED, topping the performance charts.*[124]

Wells Fargo's position has been echoed by a variety of equity and debt investors and industry participants. For example, Moody's noted that "[l]ong-term challenges to natural gas infrastructure

123 Direct Testimony and Exhibits of Mark Ewen and Robert Knecht, Docket No. 21-09, November 8, 2021, at 23. ***Emphasis added***.

124 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

are increasing," which raises "operating risks and cost of capital."[125] As noted above, Brattle has stated that "gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals."[126] Additionally, as discussed in more detail below, S&P has observed that the "'electrification' movements in states like California, Massachusetts, New York and Washington are raising questions about the future of gas utilities in the U.S."[127]

From an investor's perspective, both short-term and long-term risk is important. If the Company's ability to operate as a going concern over the long-term is impeded because of changes in policy or investor sentiment, it will be difficult, if not impossible, for regulation to fully mitigate that risk for investors.

5. The European Case Study

Generally, the pace and status of the Energy Transition differs by region. Regions that are further along in the Energy Transition can serve as instructive examples of what is to come for regions that are further behind. Therefore, we have examined Europe's gas utilities, which operate in a region that is ahead of many others in the Energy Transition, as a case study in the future of Canadian gas utilities if the Energy Transition continues.

S&P observes that "Europe is ahead of many regions in energy transition, which increases longer-term business risks for the gas industry."[128] Specifically, S&P states:

> *Demand for natural gas in Europe is extremely unlikely to expand over the next decade. S&P Global Platts Analytics expects accumulated demand decline of 11.5 billion cubic metres (bcm) in 2020-2030. Although carbon dioxide emissions from gas are about 50% lower than those from coal, this is not enough to make gas compatible with Europe's decarbonization targets and with the EU Green Taxonomy.*[129]

[125] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

[126] Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

[127] S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

[128] S&P Global Ratings, "As Europe's Gas Markets Slowly Stall, Gas Producers' and Utilities' Business Risks May Rise," November 16, 2020, at 1. We note that S&P's comments pre-date the war in Ukraine, which has increased the focus on European energy supply.

[129] *Ibid*.

S&P further notes that, considering these limitations on growth, Europe's gas utilities will need to "reduce their financial leverage" (i.e., increase the equity ratio) to maintain their credit ratings despite "supportive and very predictable regulations." Specifically, S&P concludes:

> *At present, regulated gas transmission and distribution companies still benefit from supportive and very predictable regulations, which underpin their resilience. Despite this, we anticipate that they will need to reduce their financial leverage if they are to maintain ratings at the current level. There are limited growth prospects for gas infrastructure, and alternative growth paths, like diversifying into hydrogen, carry technological and regulatory uncertainties.*[130]

The path for Enbridge and other North American utilities may deviate from those in Europe, but the trends are likely to be comparable. As discussed in more detail in the next section, the Company has experienced, and is projected to continue experiencing, declining use per customer and declines in the number of new customers per year. Therefore, while the Company's present situation does not precisely mimic that of Europe's gas utilities, those utilities nonetheless serve as an instructive case study.

6. Conclusions

The Energy Transition represents a radical transformation of the long-term risk environment for Enbridge Gas relative to 2012 (i.e., the time of OEB's last equity thickness assessments for the Company). Since 2012, both the Canadian federal government and the U.S. federal government committed to achieving net zero greenhouse gas emissions by 2050. The Trudeau administration imposed a carbon tax that is projected to hit $170 per metric tonne by 2030. Utilities with a collective market capitalization of several hundred billion dollars have similarly committed to achieving net zero emissions by 2050 or earlier. Investors collectively managing trillions of dollars of assets are also pursuing aggressive emission reduction targets. Dozens of municipalities in the Company's service territory have declared climate emergencies, and there have been several calls for the phase-out of gas in Ontario from home heating and electric generation.

Enbridge and Enbridge Gas are taking steps to actively position the companies in response to the Energy Transition. These steps include issuing SLBs that tie its cost of debt to its ability to achieve ESG goals; committing to net-zero emissions by 2050; and for Enbridge Gas investing in pilot projects for hydrogen, RNG, hybrid heating, IRPAs, and demand-side management more broadly. While these measures provide future growth pathways for the Company, they do not eliminate the substantial

130 *Id.*, at 2.

increase in uncertainty created by the Energy Transition. Further, in the case of the SLB issuances, these measures directly link the cost of capital to the ability to achieve ESG goals.

Investors are increasingly recognizing the effect of the Energy Transition on gas LDCs. For example, Moody's has opined that "[l]ong-term challenges to natural gas infrastructure are increasing" and that "carbon reduction commitments raise operating risks and cost of capital."[131] Brattle noted that "gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals."[132] Wells Fargo observed that this represents "a stark change from 5+ years ago when LDCs were considered to offer more sustainable growth at a lower risk profile."[133]

We have identified a number of discrete ways in which the Energy Transition affects Enbridge Gas's business risk profile, including increasing the Company's volumetric risk and operational risk, creating transition risk and stranded asset risk, and even jeopardizing the Company's ability to continue operating as a going concern. We expect regulation to partially mitigate, but not eliminate, these risks. For example, accelerating depreciation rates and approving SFV rate design may reduce the Company's stranded asset risk and volumetric risk, respectively. However, in the context of the Energy Transition, these measures are defensive in nature. From an investor's perspective, there is still the risk that they may not work. In other words, there is no scenario under which the Company is less risky today than it was in 2012.

Finally, the Energy Transition affects the Company's business risk today despite its multi-decade time horizon because utility assets are long-lived. That is why utility regulators in Massachusetts, New York, California, and California opened dockets investigating the future of natural gas utilities. As Moody's recently observed:

> *Energy companies are pursuing emission reduction goals by emphasizing efficiencies, demand-side management and electrification – that is, the process of converting services and products that historically relied on fossil fuels (such as cooking stoves, heating systems and powertrains) to electric power. Occasional gas explosions in residential neighborhoods only heighten the political and social scrutiny on the sector and on the fuel's role in providing energy. These concerns increase risks for gas investments made today, given the long-lived nature of the assets and related environmental, social and governance (ESG) considerations, such as emissions levels,*

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131 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

132 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 15.

133 Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.

> *public health and safety, corporate reputational risk, financial policies and the cost of capital over a multi-decade time horizon.*[134]

[134] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 2.

SECTION 4(b):
VOLUMETRIC RISK

Introduction

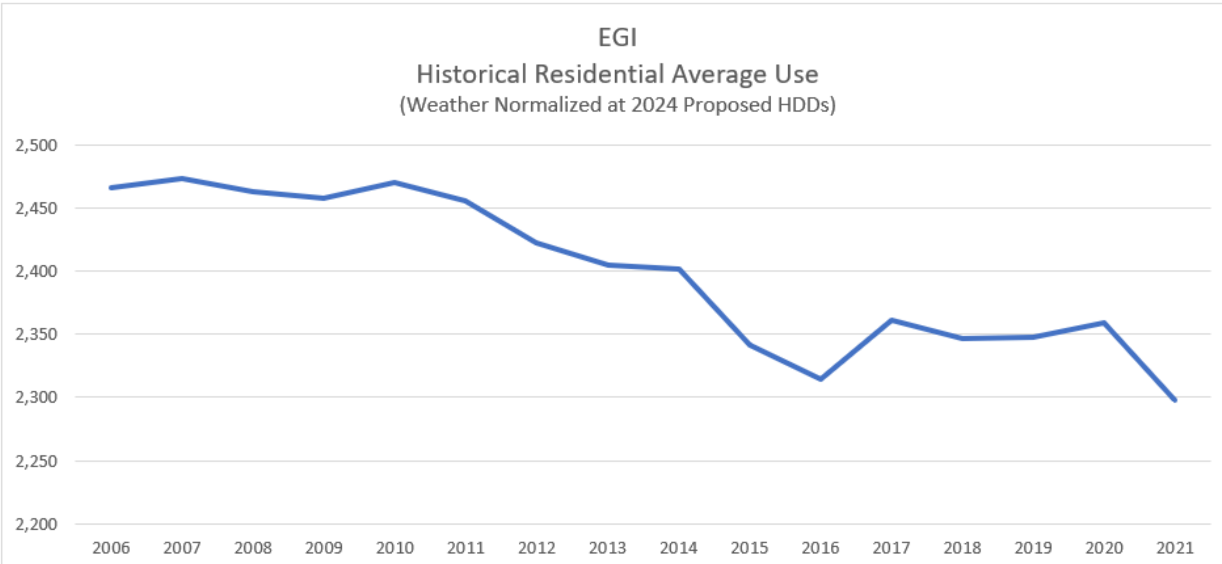
In EB-2011-0354, the OEB found that there was "no dispute that average use has declined and continues to do so."[135] However, the OEB determined that this development did not increase the Company's risk relative to 2007 (i.e., the period in which the OEB had previously examined the Company's equity thickness) for several reasons, including:

- Declines in use per customer are mitigated by customer additions.[136]
- Shale gas strengthens the competitive position of natural gas relative to alternative fuel sources such as oil and electricity.[137]
- Regulatory mechanisms such as rate design and deferral and variance accounts protect the Company's revenues from declines in its sales volumes.[138]
- A "death spiral" is unlikely from declines in average use per customer because declining usage also decreases commodity costs.[139]

Figure 9 presents the normalized average use of natural gas by the Company's residential customers from 2006 to 2021. This figure shows that normalized residential average use has declined even further from 2012 levels. In fact, for the period 2006 to 2012, the average annual growth rate in residential average use was -0.30%. For the period 2013 to 2021, the average annual growth rate decreased to -0.57%.

135 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 9.
136 *Ibid*.
137 *Id*., at 9-10.
138 *Id*., at 10-11.
139 *Id*., at 11.

Figure 9: Annual Average Use Per Residential Customer (2006 – 2021)



Considering the Energy Transition risks discussed above, we conclude that the Company's growth prospects today are weaker than they were at the time of the Company's previous equity thickness proceeding (i.e., 2012). Further, Figure 10 compares a variety of long-term economic growth projections from 2012 to comparable projections today. As shown, long-term economic growth prospects in Ontario, Canada overall, and the U.S. are weaker today than they were in 2012, diminishing the Company's growth prospects relative to 2012 even absent Energy Transition risks.

Figure 10: Comparison of Economic Growth Projections (2012 and Current)

Projection Source	2012	Current	Conclusion
Conference Board of Canada (Ontario Projections)	While the near term will be challenging for Ontario, the long-term prospects are brighter. With a large deficit to bring under control, provincial government spending on goods and services will post only limited gains until 2017-18. Strong population growth, combined with an improving economy south of the border, will offset the weakness in Ontario's public sector.[140]	Population aging is bad news for the Ontario government, which was running huge deficits and a massive debt even before the pandemic. Both exploded during COVID-19 and will linger well into the long term.[141]	**Worse** Current Outlook
Consensus Economics (Canada Projections)	Projected Real GDP Growth:[142] Year 3: 2.3% Year 4: 2.5% Year 5: 2.3% Year 6: 2.1% Years 7-10: 2.0%	Projected Real GDP Growth:[143] Year 3: 2.1% Year 4: 2.0% Year 5: 1.8% Year 6: 1.8% Years 7-10: 1.8%	**Worse** Current Outlook
Consensus Economics (US Projections)	Projected Real GDP Growth:[144] Year 3: 2.8% Year 4: 3.1% Year 5: 2.8% Year 6: 2.7% Years 7-10: 2.5%	Projected Real GDP Growth:[145] Year 3: 1.8% Year 4: 2.2% Year 5: 2.0% Year 6: 1.9% Years 7-10: 1.9%	**Worse** Current Outlook
Blue Chip Financial Forecasts (US Projections)	Projected Real GDP Growth:[146] First Five Years: 2.9% Next Five Years: 2.5%	Projected Real GDP Growth:[147] First Five Years: 2.1% Next Five Years: 2.0%	**Worse** Current Outlook

We are cognizant of the OEB's findings in EB-2011-0354 that "the issue in this proceeding is not whether average use has declined; it is whether the declining average use presents a larger risk than

[140] The Conference Board of Canada, Provincial Outlook 2012: Long-Term Economic Forecast – Executive Summary, at ii.
[141] The Conference Board of Canada, Provincial Outlook to 2041, updated October 13, 2021.
[142] Consensus Forecasts by Consensus Economics Inc., Survey Date October 8, 2012, at 28.
[143] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2022, at 28.
[144] Consensus Forecasts by Consensus Economics Inc., Survey Date October 8, 2012, at 3.
[145] Consensus Forecasts by Consensus Economics Inc., Survey Date April 11, 2022, at 3.
[146] Blue Chip Financial Forecasts, Vol. 31, No. 12, December 1, 2012, at 14.
[147] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14.

in"[148] the Company's previous equity thickness proceeding. Therefore, the sections that follow discuss the factors previously identified by the OEB as mitigating the risk created by declines in average use per customer.

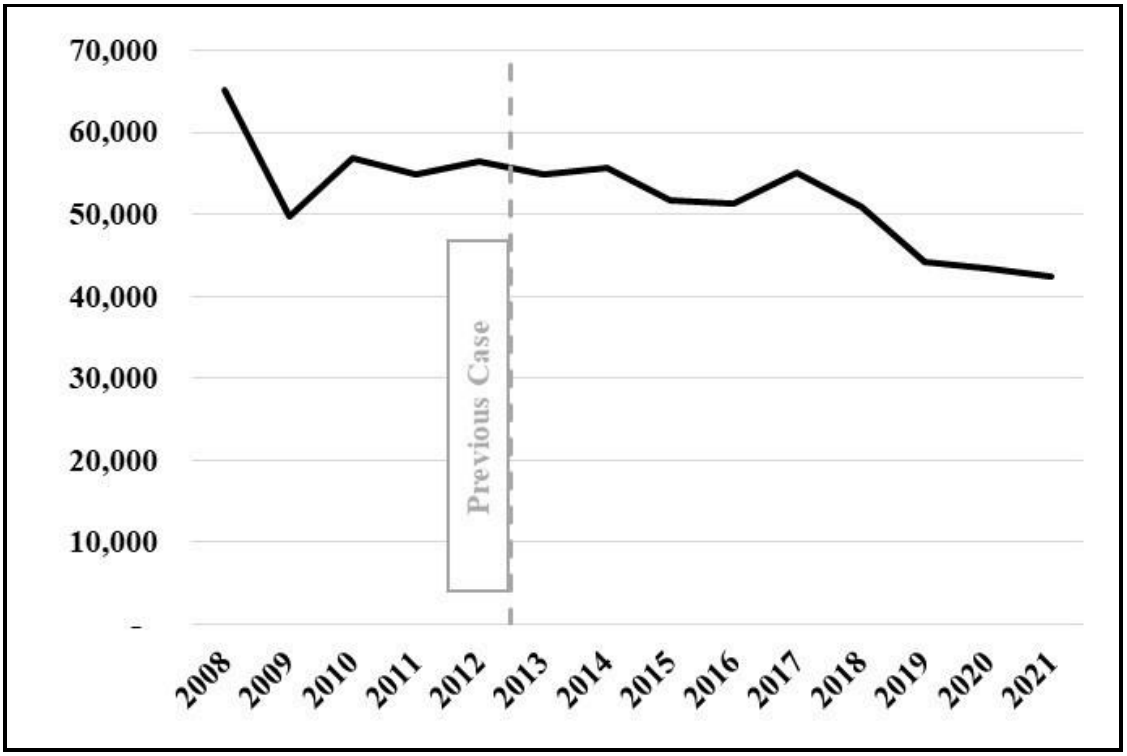
Customer Additions

In EB-2011-0354, the OEB noted that intervenors "submitted that an increase in the number of Enbridge customers mitigates the impact of declining average use."[149] While the OEB did not find explicitly that this mitigated the effects of declining average use per customer, the OEB did state that "Enbridge has added customers each year since 2007, an overall increase of 11% from 2007 to its forecast for 2013. The OEB notes that although Enbridge has expressed concern about the fact that most new customers are weather-sensitive, its evidence indicates that weather risk has not increased since 2007."[150]

The Company's rate of customer additions has continued declining since 2012, as shown in Figure 11. Specifically, the Company added approximately 56,500 on average from 2008 to 2012. In contrast, the Company added approximately 50,000 customers on average from 2013 to 2021, a 12 percent decrease from the 2008 to 2012 period. The Company added 42,500 customers in 2021, which represented the lowest amount of customer additions over the entire period from 2008 to 2021. As such, while the Company continues to add customers, it has steadily added fewer and fewer over time, a trend that has accelerated since about 2017.

[148] EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 9.
[149] *Id.*, at 8.
[150] *Id.*, at 9.

Figure 11: Annual Customer Additions (2008 – 2021)



Further, we expect the number of customer additions each year to continue declining for three reasons: (1) the Energy Transition, (2) a weaker economic growth outlook, and (3) the OEB's generic proceeding on community expansion. The Energy Transition and economic growth outlook were both discussed previously, and the OEB's generic proceeding on community expansion is discussed below.

In EB-2016-0004, the OEB indicated that qualified parties may compete for the right to serve areas that do not currently receive gas distribution service, even if one utility already holds a franchise agreement or certificate with that municipality.[151] The OEB's decision allows utilities to charge "stand-alone" rates to new expansion communities that are higher than the rates charged to the rest of the utility's customers.[152] This shift in the competitive landscape has already affected expansion projects in several communities, including South Bruce (where EPCOR was selected to provide service instead of Enbridge Gas),[153] Fenelon Falls (where Enbridge Gas was selected),[154] Bobcaygeon (Enbridge Gas paused this project after initially not being awarded a government grant; the project

151 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016.
152 *Id.*, at 18.
153 *Ibid.*
154 EB-2017-0147, Ontario Energy Board Decision and Order, March 1, 2018.

was recently resumed after receiving a recent round of funding),[155] and others. The OEB recognized that this increases forecast risk borne by utilities:

> *Competing utility companies would be incented to provide rates favourable to customers in order to be selected as the preferred proponent of the expansion project. The selected proponent would then be incented to maintain low rates in order to be attractive to potential customers which would in turn should [sic] increase its margins. A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs. The utility would bear the risk for that 10-year period if the customers they forecast did not attach to the system. At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected. The cost is absorbed into rates and paid for by other ratepayers.*[156]

We conclude that EB-2016-0004 moderately increases the Company's risk relative to 2012 in two ways: (1) it increases the Company's exposure to forecast risk, as noted by the OEB, and (2) it weakens the Company's growth prospects because it now faces increased competition from other utilities to serve currently unserved areas.

Regulatory Mechanisms

In EB-2011-0354, the OEB noted that regulatory mechanisms such as rate design and deferral and variance accounts "operate to protect Enbridge's revenues."[157] The OEB elaborated, finding:

> *Enbridge now collects a greater portion of its revenues from fixed charges than in 2007. Enbridge does not consider that this reduces risk. An Enbridge witness indicated that this change was made for purposes of reflecting cost causality more accurately. However, the Board agrees with the intervenors that this change also helps to mitigate risk. Distribution costs are largely fixed. If more of the costs are recovered through fixed charges, there is less revenue volatility related to volume changes, and less uncertainty that the fixed costs will be recovered. This mitigation is greater now than it was in 2007, since Enbridge's forecast for 2013 shows 51% of revenues collected through fixed charges, a significant increase over 33% in 2007. In addition, Enbridge has benefited from a growing customer base over which to recover its fixed costs. This means that Enbridge's revenues are now less dependent on volume than in 2007.*[158]

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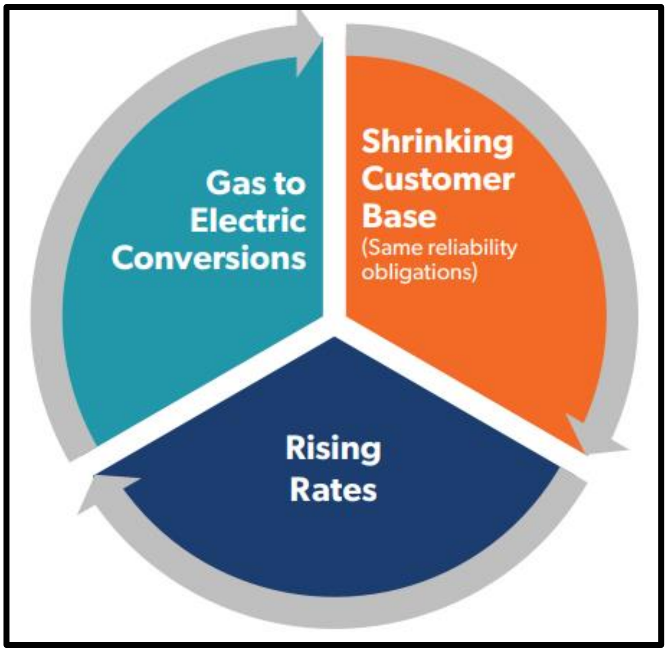
155 EB-2017-0260, Letter from Joel Denomy to Kirsten Walli, July 10, 2018.
156 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016, at 20.
157 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 10.
158 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016, at 20.

We note that the Company is proposing a SFV rate design in this case. If approved, this proposal would further decrease the Company's exposure to volumetric risk. We note that the Company continues to benefit from regulatory mechanisms such as deferral and variance accounts that mitigate the potential financial impact of declining sales volumes (although these accounts may be discontinued if the Company's SFV proposal is approved). For these reasons, we conclude that the Company has regulatory mechanisms that mitigate the Company's volumetric risk in the near-term. However, as discussed in more detail in the following section, we conclude that the Company's long-term volumetric risk has increased.

"Death Spiral" Risks

Over the long-term, gas distribution utilities such as Enbridge Gas face the risk that they will lose customers and load to electrification and other energy sources. However, gas distribution utilities must continue investing in their systems in the short-term to maintain the safe and reliable provision of utility service. Together, those two factors mean it is possible that gas distribution utilities face what has been termed a "death spiral" whereby an increasing amount of cost must be recovered from a continually shrinking customer base. In a death spiral scenario, the resulting rate increases provide incentives to customers to leave the gas system, creating a negative feedback loop of rate increases and customer departures. Brattle created the following figure illustrating this scenario.

Figure 12: Brattle Illustration of Death Spiral Risks[159]



A future "death spiral" is far from certain, and we anticipate that the Company will work proactively to avoid such an outcome. However, it is possible. In 2020, residential customers accounted for approximately 57% of the Company's revenues but just 32% of its sales volumes.[160] If a meaningful portion of these customers switch to non-gas heating sources, whether due to technological advancements, environmental concerns, or policy mandates, costs will increase for the Company's remaining customers. Such a scenario could potentially spark a so-called "death spiral."

Due to the acceleration of declines in average use per residential customer, declines in the rate of customer additions, a relatively weaker economic growth outlook, the OEB's encouragement of competition, and the Energy Transition pressures, we conclude that the risk of a "death spiral" is higher today than it was in 2012. Further, while the Company benefits from a variety of ratemaking mechanisms that provide risk insulation in the short-term, regulation can do little to mitigate these longer-term pressures because this scenario is driven by economics, not regulatory pressures.

Conclusions

The Company's average use per residential customer has continued to decline since 2012, and its growth prospects today are weaker than they were in 2012. The Company had, and continues to

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[159] The Brattle Group, "The Future of Gas Utilities Series: Transitioning Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.

[160] Enbridge Gas Inc., Consolidated Financial Statements, December 31, 2020, at 14; and Company-provided data.

have, a variety of ratemaking mechanisms, such as its rate design and deferral and variance accounts, that protect against this risk in the short-term. That protection will increase if the Company's SFV rate design proposal is adopted. However, in the long-term, it is much more difficult for regulation to protect against volumetric risks such as "death spiral" risks. We do not expect a death spiral scenario to be likely for Enbridge Gas because it is reasonable to anticipate both the Company and its regulators would work proactively to avoid such a scenario. That said, comparatively, the risks of the death spiral scenario today are higher than they were in 2012.

We conclude that the Company continues to face limited short-term volumetric risk, but the Company's mid to long-term volumetric risk is meaningfully higher today than it was in 2012. Even with the uncertainty associated with how the Energy Transition will evolve and how consumers will respond, from an equity investor's perspective, the hydrocarbon intense gas distribution business is a less attractive industry.

SECTION 4(c):
FINANCIAL RISK

Financial risk exists to the extent a company incurs fixed obligations that are senior to common equity in financing its operations. These fixed obligations increase the level of income that must be generated to cover interest payments before common stockholders receive any return, directly impacting equity investors in addition to business risks. Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions, such as those that occurred during the financial market disruptions of 2008 and 2009, and more recently the COVID-19 global pandemic.

Financial risk is assessed in terms of credit metrics, credit ratings, capital structure, and authorized return. Credit metrics provide a snapshot of how the company is financed and to what extent fixed obligations absorb income and cash flows. Credit analysts focus on the potential for default on debt obligations and rate the financial strength of the companies they cover, with A-range entities being more resilient and anything less than investment grade, i.e., BB+ or lower (for S&P, DBRS and Fitch), or Ba1 and lower (for Moody's), being more volatile and higher risk. It is important to note that ratings agencies analyze the default risk for *debtholders* and they consider equity as a cushion for debt, but do not focus on the residual risk to the *equity shareholders*. Oftentimes, those risks are aligned at a macro level, but there have been notable cases where credit ratings have not been a good measure of shareholder risk. That is the case, for example, where a credit rating is supported at the expense of shareholders, lowering risk to creditors but increasing risk to shareholders.[161]

Credit ratings do, however, send important signals to investors. Regulators recognize that lower credit ratings result in higher debt costs and reduced financial flexibility to manage unexpected events. Credit downgrades can limit companies' access to capital markets, reduce their ability to issue commercial paper to finance short-term working capital requirements, lead to violations of loan covenants, or force a utility to issue equity at unfavorable times. A significant setback in operations

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[161] *See* Maritimes & Northeast Pipeline ("M&NP"), which had its A rating confirmed in April 2009 despite the fact that since November 2007, all cash distributions to equity owners were escrowed for the benefit of lenders. See DBRS, Maritimes & Northeast Pipeline Limited Partnership Report, April 9, 2009, where it states "…Consequently, M&NP Canada's equity owners (77% Spectra Energy Corp, 13% Emera Inc. and 10% ExxonMobil Corporation (ExxonMobil)) have not received cash distributions since November 30, 2007. This will continue until cash balances have been built up to an amount sufficient to meet all remaining scheduled principal and interest payments on the M&NP Canada Notes until maturity in November 2019. DBRS notes that the conventional natural gas reserve outlook for the east coast of Canada has deteriorated since the Test was incorporated into the M&NP Canada financing documents in 1999. Consequently, the M&NP Canada noteholders have the benefit of this protection."

could result in a credit rating downgrade to below investment grade. In other words, the closer a company operates to the threshold of an investment grade credit rating, the greater the risk that unanticipated market or business events could lead to credit downgrades.

Figure 13 shows the credit ratings that rating agencies issue. For each rating category, except the lower ratings, Moody's also attaches a 1, 2, or 3 to designate whether credit quality is at the high, medium, or low end of the rating category, respectively. Similarly, S&P attaches a "+" or a "-" designation and DBRS uses a "high" or "low" designation to a rating to indicate "notches" above or below the grade. All ratings above the line are deemed to be "investment grade".

Figure 13: Credit Ratings

	Moody's	**S&P**	**DBRS**
Investment Grade	Aaa	AAA	AAA
	Aa	AA	AA
	A	A	A
	Baa	BBB	BBB
Speculative	Ba	BB	BB
	B	B	B
	Caa	CCC	CCC
	Ca	CC	CC
	C	C	C

Ratings determinations are made on the basis of the company issuer's business and financial risk profiles. Concentric notes that in the OEB's last review of EGD's equity thickness, the OEB delineated its basis for determining whether financial risk had changed:

> *The Board considers that in assessing whether Enbridge's financial risk has increased since 2007, the appropriate indicators are the key elements of Enbridge's market circumstances: access to capital, interest coverage ratios, credit ratings, debt terms, and financial results.*[162]

Concentric has reviewed EGI's financial risk in the context of its market circumstances as the OEB instructed in the above-cited Decision and provided an assessment of the status of each component

[162] OEB Decision on Equity Ratio and Order, EB-2011-0354 (February 7,2013), at 16.

and how each of the components has changed since 2012. The results of Concentric's review are summarized in Figure 14 below and are discussed in greater detail in the following pages.

Figure 14: Financial Risk Summary

Access to Capital/ Liquidity	Credit Metrics	Comparative Metrics	Credit Rating and Debt Terms	Financial Results	Conclusion
Unchanged	Weaker	Weaker	Unchanged	Unchanged	Financial risk has slightly increased and EGI's financial profile is weaker than its peers' financial profiles

Access to Capital/Liquidity

According to S&P's most recent ratings report on EGI, EGI's liquidity is assessed as adequate.[163] As an A- rated regulated utility, EGI is able to access capital markets under a reasonable range of market circumstances. The Company maintains an "A" rating from DBRS, which commented that the Company has "solid liquidity and low refinancing risk."[164] Concentric's assessment is that EGI's ability to access capital is substantially unchanged since its last equity thickness review and evidence in 2012.

Credit Metrics

Ratings agencies and financial analysts look at several credit metrics to assess the financial strength of a utility. S&P relies on cash flow/leverage analyses ("core ratios") to determine the preliminary cash flow assessment of a company, and then considers a number of interest coverage and payback ratios to enhance its understanding of the final financial risk profile of the company. For a regulated utility with stable cash flows, S&P typically applies its "low volatility" table as shown in Figure 15 to assess the strength of its financial profile, and, depending on its evaluation of the issuer's credit metrics, assesses the issuer's financial risk from "Minimal" to "Highly Leveraged." Figure 16 shows the credit metrics that align with each financial risk assessment. S&P assesses EGI as having "Significant" financial risk.

[163] S&P Global Ratings, Ratings Direct, Enbridge Gas, Inc., February 1, 2022.
[164] DBRS Morningstar, Ratings Report, Enbridge Gas, Inc., October 5, 2021.

Figure 15: S&P Financial Risk Criteria

Cash Flow/Leverage Analysis Ratios--Low Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	35+	Less than 2	More than 8	More than 13	More than 30	20+	11+
Modest	23-35	2-3	5-8	7-13	20-30	10-20	7-11
Intermediate	13-23	3-4	3-5	4-7	12-20	4-10	3-7
Significant	9-13	4-5	2-3	2.5-4	8-12	0-4	0-3
Aggressive	6-9	5-6	1.5-2	1.5-2.5	5-8	(10)-0	(20)-0
Highly leveraged	Less than 6	Greater than 6	Less than 1.5	Less than 1.5	Less than 5	Less than (10)	Less than (20)

In addition, as noted below, S&P also evaluates business risk, with its assessment spanning from "Vulnerable" to "Excellent." S&P combines its financial risk assessment with its business risk assessment in accordance with the below risk matrix to determine its "Anchor assessment" for the issuer. Because of their strong business risk profiles, underpinned by rate-regulated utility revenues, North American utilities, including EGI, are typically afforded higher credit ratings than they would be if they operated in competitive markets, even when utilities have financial profiles that contain relatively high levels of debt. For example, a company such as EGI, which has a "Significant" financial risk assessment, will still fall within the "a-" Anchor assessment due to its "Excellent" business risk assessment. Potential modifiers to S&P's Anchor assessment, such as ESG considerations,[165] are then considered to arrive at the stand-alone credit profile for an entity.[166]

[165] Standard and Poor's Rating Services, Ratings Direct, The Role of Environmental, Social, and Governance Credit Factors in Our Ratings Analysis, September 12, 2019.

[166] Standard and Poor's Rating Services, Ratings Direct, Corporate Methodology (November 19, 2013), at 8-12.

Figure 16: S&P Anchor Assessment Criteria

Combining The Business And Financial Risk Profiles To Determine The Anchor

	--Financial risk profile--					
Business risk profile	**1 (minimal)**	**2 (modest)**	**3 (intermediate)**	**4 (significant)**	**5 (aggressive)**	**6 (highly leveraged)**
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

A review of key credit ratios for EGI's regulated operations since 2012 indicates a slight and gradual decline in financial strength over that period. Below, Concentric has summarized the credit metric history for the regulated operations of both EGD and Union Gas from 2012 to 2018, and the regulated credit metrics of the amalgamated entity since 2019. This summary was calculated using S&P's methodology and includes S&P's "core ratios" (i.e., Funds From Operations ("FFO")/Debt and Debt/Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA")), supplementary coverage ratios (i.e., FFO Cash Interest Coverage and EBIT/Interest coverage), debt capitalization, and earned return on equity for each of Union Gas and EGD (pre-amalgamation), and EGI (post-amalgamation). These credit metric calculations are for EGI's regulated operations only and reflect the adjustments consistent with S&P's approach to the calculations. These metrics may differ from those reported by credit agencies, as those metrics are calculated on consolidated entity results, whereas these values are for regulated operations only.

Figure 17: EGD/EGI Financial Metrics

	2012	**2021**	**% Change**	**Trend**
Debt/EBITDA	4.42	5.94	34.4%	Deteriorating
FFO/Debt	15.69%	12.19%	22.3%	Deteriorating
FFO/Interest Coverage	3.83	3.92	2.3%	Stable
EBIT/Interest Coverage	2.03	2.35	15.8%	Improving
Debt/Capitalization	64.0%	64.0%	0%	Stable

As Figure 17 above shows, since 2012 EGD/EGI's core ratios from S&P have deteriorated, with Debt/EBITDA (lower is better) increasing by approximately 34 percent from 2012 through 2021 and FFO/Debt (higher is better) decreasing by about 22 percent over the same period. The interest coverage ratios have been stable-to-improving, with FFO/Interest coverage (higher is better) increasing by 2.3 percent and EBIT/Interest coverage (higher is better) increasing by 15.8 percent. The Debt/Capitalization ratio on a regulatory basis has remained the same at 64.0 percent.

Figure 18: Union Gas/EGI Financial Metrics

	2012	2021	% Change	Trend
Debt/EBITDA	4.70	5.94	26.4%	Deteriorating
FFO/Debt	14.24%	12.19%	14.4%	Deteriorating
FFO/Interest Coverage	3.35	3.92	17.0%	Improving
EBIT/Interest Coverage	2.13	2.35	10.3%	Improving
Debt/Capitalization	64.0%	64.0%	0%	Stable

The credit metrics trends for Union Gas/EGI are similar to those for EGD/EGI since 2012. As shown in Figure 18, since 2012 Union Gas/EGI's core ratios from S&P have deteriorated, with Debt/EBITDA (lower is better) increasing by approximately 26 percent from 2012 through 2021 and FFO/Debt (higher is better) decreasing by about 14 percent over the same period. The interest coverage ratios have improved, with FFO/Interest coverage (higher is better) increasing by about 17 percent and EBIT/Interest coverage (higher is better) increasing by just over 10 percent. The Debt/Capitalization ratio on a regulatory basis has remained the same at 64.0 percent.

As discussed in Section 5: Fair Return Standard Analysis, Concentric reviewed capital structure and other data from multiple proxy groups. Based on a comparison of EGI's credit metrics to its peers in those proxy groups,[167] Enbridge Gas has on average a weaker financial profile than both the Canadian and U.S. holding company proxy groups and the U.S. operating company proxy groups. As shown in the figure below and detailed more fully in Schedule 1, EGI's credit metrics are comparatively weaker than the proxy group averages, with the exception of Debt/EBITDA and FFO/Debt in the Canadian

[167] The identification of Enbridge Gas' peer companies is discussed in more detail in Section 5, below.

Holding Company group. All other metrics are stronger for the proxy group than EGI. In Concentric's view, Enbridge Gas' financial profile is comparatively weak relative to its peer companies.

Figure 19: Comparison of Enbridge Gas' Credit Metrics to the Proxy Companies

Company / Proxy Group	Debt to Capital Ratio	EBIT/ Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Enbridge Gas Inc. (S&P)	49.7%	4.29	4.33	12.4%	6.21
Enbridge Gas Inc. (Reg-only)	64.0%	2.35	3.92	12.19%	5.94
Canadian OpCo Average [1]	N/A	N/A	N/A	N/A	N/A
Canadian HoldCo Average	58.0%	4.08	4.20	11.5%	6.53
US OpCo Average	49.7%	8.34	10.18	19.3%	4.56
US HoldCo Average	57.8%	6.94	5.51	14.2%	5.75

Notes:
[1] Insufficient companies in this proxy group are rated by S&P to produce meaningful results.

Figure 20 presents the forecasted credit metrics for Enbridge Gas for 2022-2024 as compared to the Company's actual credit metrics in 2021. As this analysis demonstrates, Enbridge Gas anticipates modest improvements in core metrics through 2023 as compared to 2021, although not returning to the levels achieved in 2012. Enbridge Gas is projecting more marked improvement in 2024, coinciding with the beginning of the phase in of the Company's proposed increase to its deemed equity ratio. As shown in the figure, however, maintenance of the Company's 36% equity ratio would impair those improvements, and in some cases (e.g., Debt/EBITDA, EBIT/Interest Coverage) leave Enbridge Gas's credit metrics at the same or worse levels in 2024 compared to 2023.

Figure 20: EGI Forecast Credit Metrics

	2021 A	2022 F	2023 F	2024 F	2024 F (no change in cap structure)
Debt/EBITDA	5.94	5.88	5.74	5.03	5.24
FFO/Debt	12.19%	12.47%	12.75%	14.49%	13.76%
FFO/Interest Coverage	3.92	3.98	4.05	4.44	4.25
EBIT/Interest Coverage	2.35	2.31	2.42	2.55	2.40

	2021 A	2022 F	2023 F	2024 F	2024 F (no change in cap structure)
Debt/Capitalization	64.0%	64.0%	64.0%	62.0%	64.0%

Credit Rating and Debt Terms

In Canadian credit markets, a downgrade below an "A-" rating grade may have significant financial impacts since there is less trading of lower-rated investment grade debt (i.e., below the "A-" ratings grade). Less trading occurs at the below A-rated level because institutional investors often face limits or are precluded from investing in "Baa/BBB" rated debt. Further, in the financial market dislocation of 2008 and 2009, regulated issuers below an "A-" credit rating were effectively shut out of the Canadian credit market.[168] In the recent global pandemic, as described in more detail later in this section, low A issuers like EGI, were able to access credit markets, but the credit terms (i.e., spreads over government bonds) were less attractive than typical. Many Canadian regulators acknowledge the desirability for utilities to maintain a strong credit rating to lower debt costs and increase financial flexibility. In the British Columbia Utilities Commission's ("BCUC's") 2013 Generic Cost of Capital Decision, the BCUC Panel found that "there [was] sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs."[169] The AUC also targets an "A" credit rating when setting the authorized capital structure for regulatory purposes.

Since 2012, EGD has been rated A- by S&P, except for a two-and-a half-year period where EGD's credit rating was downgraded to BBB+ from June 2015 to November 2017 due to weak forecast financial metrics at Enbridge. During this period, EGD's ratings outlooks fluctuated between "Stable," "Watch Negative," and "Negative." Since 2012, Union Gas was rated BBB+ until February 2017, when it was upgraded to A- by S&P as a result of the announced merger between its parent, Spectra Energy Corp., and Enbridge Inc. Both EGD and Union gas maintained "A" ratings from DBRS, and neither entity was rated by Moody's.

S&P characterizes EGI's key strengths as: (1) a low-risk rate-regulated utility; (2) approximately two-thirds of distribution revenue comes from residential and small business customers; and (3)

168 See AltaLink 2011-2013 GTA Decision 2011-453, paragraph 798, where the Alberta Commission states: "A list of individual debt transactions provided by AltaLink shows that during the period June 11, 2008, to January 29, 2009, companies with credit rating outside of an A category were not able to issue long-term debt on any terms in the public Canadian debt market."

169 BCUC Generic Cost of Capital Decision, Stage 1, May 10, 2013, at 50.

quarterly adjustment mechanisms that pass through commodity costs to customers.[170] S&P notes that EGI's risks are that it operates solely within Ontario, limiting its ability to diversify geographic and regulatory risk, and that it has negative discretionary cash flow, indicating external funding needs.[171] S&P also notes that EGI's capital expenditure program in 2022-2023 "is about 2.0x its depreciation cost, which we expect will lead to negative discretionary cash flow over our forecast period, resulting in external funding needs."[172] S&P specified a downside scenario if the utility's financial measures deteriorate, with FFO/Debt approaching 10% with no prospects for improvement, or if it were to lower ratings on its parent Enbridge Inc., which could happen if Enbridge Inc.'s FFO/Debt were to stay below 13% or Debt/EBITDA is sustained above 5x.[173] Though S&P indicated an upgrade was unlikely, S&P stated that it could occur over the next 18-24 months if the Company improves its financial measures with FFO/Debt consistently above 13% (requiring its parent to have an FFO/debt above 17%), or if adjusted Debt/EBITDA were maintained at about 4x while maintaining its current level of asset mix and cash flow stability.

170 S&P Global Ratings, RatingsDirect, Enbridge Gas Inc., February 1, 2022, at 2.
171 *Ibid*.
172 *Id*., at 3.
173 *Ibid*.

SECTION 4(d):
OPERATIONAL RISK

This section discusses changes in operational risk for Enbridge Gas since 2012. Several of the Energy Transition challenges affecting the gas industry generally have consequences for the Company's operational risk. These include: (1) the move toward decarbonization in response to climate change and the associated anti-carbon sentiment in many jurisdictions across North America; and (2) the effect of climate change and severe weather risk on gas distribution utilities such as EGI and the sharpened focus on environmental risk among investors and credit rating agencies. In addition, other operational risks for Enbridge Gas have also increased since 2012, such as higher insurance costs, increased risk related to cyber-security attacks, and more complex engineering regulations on its gas distribution system. Each of these issues is discussed in greater detail in this section of Concentric's report.

Decarbonization and Anti-Carbon Sentiment

As discussed in Section 4(a): Energy Transition, anti-carbon sentiment is spreading across North America, especially at the provincial, state and municipal level in cities such as Toronto, Vancouver, and Seattle, provinces such as Ontario and British Columbia, and states such as New York, California, Massachusetts and Colorado. This is manifesting itself in various ways for gas distributors like Enbridge Gas, including prohibitions against new pipeline construction, issues with siting and permitting new gas facilities, requirements that all new construction use electricity rather than natural gas, and outright bans against natural gas by a date certain. As a result, the risk associated with project development and execution is higher because it takes longer for new projects to be approved, delays are likely to result in increased project costs, and opposition to projects causes the need for additional planning prior to permitting and construction. Moody's has observed that "[d]evelopment of oil and gas infrastructure, in particular, continues to face legal challenges from environmental groups, which are succeeding in delaying pipeline development by opposing efforts by project developers to secure needed permits."[174]

Effect of Climate Change and Severe Weather Risk

In general, weather risk has increased for utilities, as climate change and severe weather risk have continued to increase in the past decade. While much of the focus has been on electric utilities, there

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[174] Moody's Investors Service, "Shifting environmental agendas raise long-term credit risk for natural gas," September 30, 2020, at 3.

are numerous examples of gas distribution companies also being affected by severe weather risk. These include: (a) the need for Entergy New Orleans to rebuild the gas distribution system after it was flooded by Hurricane Katrina in August 2005; (b) the Texas storm that caused an electricity outage for New Mexico Gas in February 2011, resulting in the company's compressor stations going offline and the need to shut off natural gas service to more than 28,000 customers and to restore service over a period of four-to-five days; (c) the disruption caused by Enbridge pipeline's interruption in 2018 that affected gas flow to FortisBC Energy, which provides gas distribution service to more than 1 million customers in British Columbia; and (d) the 2021 winter storm in Texas that led to widespread electricity outages and caused the spot price of natural gas to spike to over $100 in Chicago when there was not sufficient power to supply many residents in Texas.

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

In May 2019, the Bank of Canada indicated that it views climate change as an emerging risk for the Canadian economy and financial system. Specifically, the Bank of Canada observed that:

> *Climate change continues to pose risks to both the economy and the financial system. These include physical risks from disruptive weather and events and transition risks from adapting to a lower carbon global economy.*[175]

The Bank of Canada indicates that it is incorporating climate change risk into its analysis of the Canadian economy and financial system, that climate change creates important physical risks in Canada and globally, and that the move to a low carbon economy involves complex structural adjustments, creating new opportunities as well as transition risk.[176]

In September 2020, the Commodity Futures Trading Commission ("CFTC"), the financial regulator that oversees the trading of futures and options in the U.S., published a report concluding that climate change is a risk to the U.S. financial system.[177] In particular, the CFTC noted the economic risk of changes that are required to mitigate climate change and the disruptive effect those changes might

175 Bank of Canada Financial System Review-2019, May 2019, at 28.
176 *Id.*, at 28-29.
177 U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System," September 9, 2020.

have on the stability of the financial system itself. The key conclusions of the CFTC report were as follows:[178]

> *Climate change poses a major risk to the stability of the U.S. financial system and to its ability to sustain the American economy. Climate change is already impacting or is anticipated to impact nearly every facet of the economy, including infrastructure, agriculture, residential and commercial property, as well as human health and labor productivity. Over time, if significant action is not taken to check rising global average temperatures, climate change impacts could impair the productive capacity of the economy and undermine its ability to generate employment, income, and opportunity.*
>
> *This reality poses complex risks for the U.S. financial system. Risks include disorderly price adjustments in various asset classes, with possible spillovers into different parts of the financial system, as well as potential disruption of the proper functioning of financial markets. In addition, the process of combating climate change itself—which demands a large-scale transition to a net-zero emissions economy—will pose risks to the financial system if markets and market participants prove unable to adapt to rapid changes in policy, technology, and consumer preferences. Financial system stress, in turn, may further exacerbate disruptions in economic activity, for example, by limiting the availability of credit or reducing access to certain financial products, such as hedging instruments and insurance.*

As previously noted in this report, rating agencies such as S&P and Moody's have incorporated ESG criteria into their credit rating analysis, while investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change.

McKinsey and Company published a report in April 2019 in which the consulting firm made specific recommendations to the utility industry with regard to managing climate change risk. While noting that severe weather events such as hurricanes and wildfires are getting worse, McKinsey wrote: "In other ways, too, utilities are more vulnerable to extreme weather events than in the past."[179] The report went on to observe: "Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage and upgrading infrastructure after the fact is expensive and traumatic."[180] McKinsey also quoted from a 2018 report by the National Climate Assessment that stated "utilities could see negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence

[178] *Id*., at i and ii.
[179] McKinsey and Company, "Why, and how, utilities should start to manage climate change risk," April 2019, at 3.
[180] *Ibid*.

of storms. This will increase the financial cost to utilities of climate change and increase the benefits of being prepared."[181]

In summary, the risks associated with changing climate parameters and severe weather events have increased for EGI since 2012, at the asset, industry, distribution system and macroeconomic levels. Investors are keenly focused on how such risks are being managed by organizations. While we expect that the risks will continue to manifest over time, current trends point to a greater and potentially more urgent likelihood of incremental expenditures and operational impacts over the upcoming rate setting period.

Higher Insurance Costs

Higher insurance costs are a risk to the extent they are not recovered in base rates. Moreover, higher insurance premiums and higher deductibles are an indication that gas LDCs are being considered higher risk by insurance companies. Enbridge, Enbridge Gas's parent, manages its insurance program at the corporate level, and insurance costs are allocated to each operating subsidiary. Over the past several years, the insurance market from which Enbridge obtains coverage has experienced changing fundamentals, which have generally led to higher prices and less availability of coverage. These changing fundamentals include: 1) falling investment returns for insurers generally; 2) a lack of long-term profitability for insurers underwriting energy industry risks due to the frequency and severity of losses that exceed premiums; 3) increases in the costs associated with insured events (generally referred to as "social inflation"); and 4) insurer reduction of availability of coverage for pipeline infrastructure. Enbridge expects that these fundamentals will continue over the long term.

Enbridge, like most other businesses, must respond to the market conditions driven by these fundamentals by balancing coverage against total costs in the most efficient structure possible. In response to current and expected market conditions, and to mitigate the rising costs of insurance, Enbridge has implemented a new insurance strategy that has increased the Company's deductibles. This will reduce coverage for smaller, more frequent events while maintaining coverage for more costly, less frequent events. Under the new insurance strategy, deductibles for liability and non-liability insurance have increased from $1 million and $10 million, respectively, in 2012 to $100 million in 2022. These increases highlight the magnitude of the change in operating risk for gas LDCs like EGI as compared to the circumstances in 2012.

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[181] *Id.*, at 4.

Safety Requirements and Cyber-Security Concerns

Recent safety incidents have caused regulators and investors to place renewed focus on gas safety as a key consideration. Examples include the Columbia Gas explosion in Lawrence, Massachusetts in September 2018, and the August 2020 gas explosion in Baltimore, Maryland. While these safety concerns are not new compared to 2012, they highlight the risk of operating a gas distribution system.

The Massachusetts Department of Public Utilities recently commented that the Columbia Gas incident was likely to affect the business and financial risk profile of the new owner and the gas industry generally, stating:

> *In Massachusetts, the effects of the Merrimack Valley incident will certainly influence investors' risk assessment of NSTAR Gas, and investors might be similarly influenced by local attempts, though unsuccessful, to restrict natural gas use, such as by the Town of Brookline. In setting this ROE, the Department has taken into account the potential enactment of additional gas safety regulations that may increase NSTAR Gas's costs in response to the heighted focus on reductions in gas leaks and an added focus on safety, all of which likely will affect the financial and business risk profile of the Company in particular, and the gas industry in general.*[182]

Cyber-security attacks such as the Colonial Pipeline ransomware attack in May 2021 are also becoming a critical issue for utilities and regulators. There was not a similar level of concern in 2012. In a November 2021 report, S&P noted the following about cyber-attacks.

> *Cyber attacks on utilities have increased substantially year-over-year and while most U.S. attacks have been domestic in origin, globally, utilities have been the target of nation states or rogue actors seeking to disrupt operations. In particular, there were several reported breaches of informational (IT) and operational technology (OT) assets, in 2020 and 2021, resulting in data and financial loss and compromised assets, through phishing and other techniques.*
>
> *The risks are not just financial. Cyber attacks can cause reputational, regulatory, and financial risks if information breaches occur. These events may also influence a utility's relationship with the customer base, weakening management's rate-setting flexibility. In addition to our evaluation of IT exposures and general cyber hygiene, utilities have a*

182 Massachusetts Department of Public Utilities, Docket D.P.U. 19-120, at 405-406.

number of potential OT vulnerabilities related to supervisory control and data acquisition (SCADA) systems among other physical asset considerations.[183]

In its 2021 Form 10-K, Enbridge included cyber-security risk as one of the risks it discloses to investors related to operational disruptions and catastrophic events. In discussing cyber-security risk, Enbridge Inc. states: "Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyber-attacks and data security breaches, as well as due to international and national political factors. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cyber-attacks. New cybersecurity regulations have recently been implemented resulting in additional regulatory oversight and compliance requirements."[184] Further, Enbridge discloses: "During the normal course of business, we have experienced and expect to continue to experience attempts to gain unauthorized access to, or to compromise, our information systems or to disrupt our operations through cyber-attacks or security breaches, although none to our knowledge have had a material adverse effect on our business, operations, or financial results."[185]

While cyber-security attacks have not yet had a material adverse effect on EGI, it represents an ongoing operational risk that was not a significant concern in 2012.

Engineering Regulations and Operational Complexity

EGI operational personnel have indicated that since 2012/2013 engineering technical regulations on its distribution system have evolved and become increasingly complex in ways that increase costs and risks for the organization. For example, environmental permitting regulations have changed quite significantly, and EGI expects those regulations to change further going forward. Project execution risk has also increased due to more stringent regulatory and permitting requirements, increased stakeholder opposition, and more uncertainty around project timing and costs. This represents a significant change in operating risk for EGI as compared to 2012. In addition, the physical assets themselves are aging. While EGI is managing this situation with asset management plans, there is a need to invest additional capital in assets to maintain safe and reliable service at the same time that there is increasing opposition to spending more on fossil-fuel based distribution systems. EGI is also managing the Energy Transition from a system design perspective, including

183 Standard and Poor's Global Ratings, "Cyber Risk in a New Era: US Utilities are Cyber Targets and Need to Plan Accordingly," November 3, 2021, at 2.
184 Enbridge Inc. 2021 U.S. Securities and Exchange Commission Form 10-K, at 44-45.
185 *Id.*, at 45.

changing where supply is coming in, where demand is, and how the system flows, as well as introducing hydrogen into the system. Changing the way the distribution system works relative to how it was originally designed has risks in and of itself. All of these factors increase the uncertainty and risk of operating the gas distribution system as compared to the situation in 2012.

Amalgamation of EGD and Union Gas

The amalgamation of EGD and Union Gas was effective on January 1, 2019. While the resulting combined gas utility now serves more than 3.8 million customers in Ontario and has higher revenues and annual throughput than in 2012, EGD was already one of the largest gas LDCs in North America in 2012 when the OEB set the deemed equity ratio at 36 percent. The amalgamation with Union Gas did not change that situation. However, S&P observes that the amalgamation with Union Gas did not increase the geographic, economic, or regulatory diversification of EGI. The Company remains wholly dependent on the economic and business environment in the Province of Ontario, as well as being dependent on the decisions of the OEB. In summary, the amalgamation of EGD and Union Gas did not reduce the operating risk profile of the resulting EGI as compared to EGD in 2012.

Conclusions

Our conclusion is that operational risk has increased for EGI compared with 2012. In particular, operational risk has increased in the following areas: 1) the Energy Transition and anti-carbon sentiment; 2) risks due to climate change and severe weather; 3) higher insurance costs; 4) safety requirements and cyber-security concerns; 4) and more stringent engineering regulations and greater operational complexity. While the Company has grown in size due to the amalgamation of EGD and Union Gas, this did not reduce the operating risk profile of the resulting EGI.

SECTION 4(e):
REGULATORY RISK

This section summarizes Concentric's assessment of EGI's regulatory risk. Concentric considers EGI's regulatory risk to have decreased modestly since 2012, assuming the Company's ratemaking proposals, and, in particular, its SFV rate design, are approved by the OEB.

Regulatory Risk Overview

A utility's regulatory framework is an important consideration for both equity and debt investors. Regulatory risk is a key component of business risk for regulated utilities. For instance, S&P Global, in its rating methodology for regulated utilities, states "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[186] Moody's, in its rating methodology for regulated electric and gas utilities, lists "Regulatory Framework" as one of "four key factors that are important in [Moody's] assessment of ratings in the regulated electric and gas utility sector."[187] Moody's states that "[a]n over-arching consideration for regulated utilities is the regulatory environment in which they operate. The nature of regulation can vary significantly from jurisdiction to jurisdiction,"[188] and the agency assigns "Regulatory Framework," together with "Ability to Recover Costs and Earn Returns," a 50% factor weighting in its ratings scorecard.

Furthermore, utility regulation is generally found by rating agencies and investors to decrease risk, all else equal, compared to competitive ventures. As stated by S&P, "[u]tility regulation, no matter where on the continuum of our assessments, strengthens the business risk profile and generally supports utility ratings."[189] S&P further notes that "[w]e therefore designate all these [North American] jurisdictions from credit supportive to most credit supportive, and these vary only in degree."[190] In its assessment of North American regulatory jurisdictions, S&P assesses Ontario as "Most credit supportive (strong)." As noted previously in this report in our discussion of financial risk, because of their strong business risk profiles, underpinned by rate-regulated utility revenues, Canadian and U.S. utilities, including EGI, are typically afforded higher credit ratings than they would

[186] S&P Global, "Key Credit Factors for the Regulated Utilities Industry," November 19, 2013, at 6.
[187] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 2.
[188] *Id.*, at 3.
[189] S&P Global, "Updated Views on North American Utility Regulatory Jurisdictions – June 2021," June 29, 2021, at 1.
[190] *Id.*, at 2.

be if they operated in competitive markets, even when utilities have financial profiles that contain relatively high levels of debt. As also noted in our discussion of financial risk, EGI is rated by S&P and DBRS. The following are findings by those credit rating agencies with regard to EGI's regulatory framework:

- ***S&P***: "Our assessment of EGI's business risk reflects our view of OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy is a flow-through costs to customers, and gas commodity costs are recovered through a quarterly adjustment mechanism from ratepayers, limiting EGI's exposure to commodity risk. "[191]
- ***DBRS:*** "The Company's ratings are supported by a stable regulatory framework in Ontario," and "[a]lmost all of EGI's assets are regulated and operate under the Ontario Energy Board (OEB)-approved, five-year price-cap IR plan from 2019 through 2023. The IR plan provides the Company with the following benefits: (A) relatively predictable earnings and cash flow through a formula…; (B) full recovery of gas supply costs with quarterly adjustments, subject to regulatory review; (C) annual updates for certain costs to be passed through to customers and a reasonable mechanism for capex recovery; and (D) a mechanism for sharing earnings with customers, which provides incentives for operational efficiency."[192]

EGI's Regulatory Framework

For 2013, both EGD and Union Gas set rates on a cost of service basis. For the 2014-2018 period, both legacy companies adopted incentive regulation ("IR") frameworks. Specifically, EGD put in place a Custom IR framework, while Union Gas operated under a Price Cap IR framework. The combined EGI has operated under a Price Cap IR framework following amalgamation. EGI, and its legacy companies, maintained a 36% equity thickness through this period, 2013 to today. The Company is proposing a Price Cap IR framework in this proceeding as well.

Concentric is of the view that IR and performance-based ratemaking ("PBR") frameworks can create additional risk for utilities. In its "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," the OEB expressed a view that "[PBR] provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-

[191] S&P Global Ratings, "Enbridge Gas Inc.," February 1, 2022, at 5.
[192] DBRS Morningstar, "Rating Report: Enbridge Gas Inc.," October 5, 2021, at 2.

maximizing companies."[193] Competitive companies are subject to a greater amount of risk than traditionally rate-regulated companies, in that competitive companies bear the incremental risk of profits significantly declining from expected levels, while having a greater opportunity to accrue profits that are over and above expectations. Competitive companies generally have lower credit ratings than Enbridge Gas and higher costs of capital. In assessing regulatory risk for the utilities sector, DBRS has indicated that it views IR as higher risk than cost-of-service regulation. While Concentric agrees with that view, we also recognize that the OEB found in EB-2016-0152 (at 104) that "[t]he OEB has not changed the capital structure of any of the gas or electric utilities it regulates when they have moved to IRM." Therefore, our equity thickness recommendation in this proceeding does not reflect increased risk related to IR.

IR frameworks, including EGI's, often include elements such as a Z-factor that allow for consideration of unexpected costs that are outside of the control of the utility's management. While such elements are generally thought to decrease risk to the utility, in practice such elements have proven to be less than comprehensive, and numerous Z-factor requests have been denied by the OEB.[194] Concentric does not consider the existence of IR elements such as the Z-factor to meaningfully change EGI's risk level. In addition, EGI, like many Canadian utilities, has a number of deferral and variance accounts in place, and is proposing a few new accounts in this proceeding (i.e., a technology and innovation fund related to the energy transition, rate harmonization, system surplus capacity, locate delivery services, open bill access revenue, and enhanced integrity management program)). EGI is also proposing to modify the existing volume variance account to include revenue variance due to weather. Even if all these new accounts are approved, EGI's risk level relative to 2012 is not materially changed on this factor.

EGI, in this application, is proposing a SFV rate design. In SFV rate design, all costs that are classified as fixed are assigned to the fixed, or demand, charge. All costs that are classified as variable are assigned to the variable, or commodity, charge. In EB-2011-0354 (at 10), the OEB found "[i]f more of the costs are recovered through fixed charges, there is less revenue volatility related to volume changes, and less uncertainty that the fixed costs will be recovered. This mitigation is greater now than it was in 2007, since Enbridge's forecast for 2013 shows 51% of revenues collected through

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193 Report of the Board, "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012, at 10, citing RP-1999-0034, Decision with Reasons, January 18, 2000.

194 *See, e.g.*, EB-2017-0045 - Halton Hills Hydro; EB-2011-0277 – Enbridge Gas Distribution; EB-2011-0025 – Union Gas; EB-2009-0332 - Horizon Utilities; EB-2008-0220 – Union Gas; and EB-2007-0881 Chatham-Kent Hydro.

fixed charges, a significant increase over 33% in 2007." SFV rate design therefore reduces cost recovery risk for EGI.

In addition to the introduction of SFV rate design, in EGI's most recent IRP, the Company requested that IRPAs, including demand-side solutions like energy efficiency programs and demand side management plans, and supply side solutions like compressed natural gas and renewable natural gas, be eligible for rate base treatment.[195] This proposal, which was approved by the OEB,[196] provides IRPAs "like-for-like" treatment with the investments and resources the IRPAs are replacing. Rate base versus O&M treatment does not in and of itself reduce risk, but Concentric finds that the OEB's approval of rate basing IRPAs in EB-2020-0091 provides more certainty around the pathway for recovery of such costs.

The factors discussed above, while reducing regulatory risk for EGI, are somewhat offset by certain factors, including the OEB's findings with respect to competition in EGI's service area (discussed below); and increased uncertainty around legislative and regulatory changes stemming from the Energy Transition (discussed previously).

Competition

As discussed previously, starting around 2016, the OEB has encouraged competition in EGI's service territory. Specifically, in certain cases in which EGI or its predecessors informed the OEB of its intent to serve an expanded area, the OEB issued a letter inviting other parties to compete for that service.[197] The affirmation of competition has also been evidenced by EPCOR's successful entrance in the Bruce community. This allowance for competition in community expansions increases risk for EGI.

Regulatory Risk Conclusion

As discussed above, Concentric considers EGI's regulatory risk to have decreased modestly, assuming the Company's ratemaking proposals, and, in particular, its SFV rate design, are approved by the OEB. Also contributing to the moderation in risk is the approval by the OEB of rate base treatment of IRPAs. Offsetting these factors are the recent introduction of competition in EGI's service area, as well as the regulatory risks associated with the Energy Transition.

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195 EB-2020-0091, Enbridge Gas Inc., at 71.
196 *Id.*, at 75.
197 *See*, *e.g.*, EB-2017-0147 - Fenelon Falls; EB-2017-0260 - Scugog Island.

SECTION 4(f):
CONCLUSIONS

We conclude that Enbridge Gas' risk profile has materially increased, primarily due to the Energy Transition, relative to the time period when the OEB most recently evaluated the Company's equity thickness. The figure below summarizes our research and conclusions regarding each of the aforementioned risk categories.

Figure 21: Risk Analysis Summary

Risk Category	Summary of Developments	Conclusion
Energy Transition	The Energy Transition began in earnest in the last five years. As investors and rating agencies widely recognize, it substantially affects the risk profile of North American gas distribution utilities, including EGI.	**Significant Increase**
Volumetric	A weaker economic outlook, the introduction of competition from alternative gas suppliers, and increased competition from electricity (i.e., the Energy Transition) have combined to increase the Company's volumetric risk relative to EGI's previous equity thickness proceedings. Regulatory mechanisms provide short-term insulation, but do not change the long-term challenges facing the Company.	**Modest Increase**
Financial	EGI has experienced a gradual weakening in its debt-related credit metrics since 2012, and its credit profile is comparatively weak relative to the proxy group companies. The Company's credit spreads on debt issuances have widened slightly since 2012.	**Modest Increase**
Operational	The complexities of operating the utility have increased, putting pressure on the Company regarding project permitting, execution, and cost recovery. Successful management of the associated rate impacts depends on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices.	**Neutral to Modest Increase**
Regulatory	SFV rate design reduces cost recovery risk, and the OEB's findings in EGI's IRP proceeding provide a pathway for rate base treatment of IRP alternatives.	**Modest Decrease** *(Assuming SFV Approval)*

In addition to the above qualitative assessments, independent market indicators regarding the perceived riskiness of Canadian utility and gas utility investments suggest that investors view Canadian and gas utility investments as having greater risk today than in 2012. Figure 22 below summarizes a variety of market risk measures in 2011, 2012 and 2022 year-to-date ("YTD"). We have several takeaways from this comparison:

- While the valuation multiples (i.e., the Price/Earnings ("P/E") ratio and Market/Book Value ("M/B") ratio) for U.S. gas utilities increased relative to 2012, that increase is likely driven primarily by falling government bond yields throughout much of that time period.
- The M/B ratio for Canadian utilities has decreased meaningfully relative to 2012 and the P/E ratio has declined slightly, both of which are notable considering the decline in Canadian government bond yields. All else equal, declining government bond yields tend to result in increased valuations for utility stocks.
- Beta coefficients have increased by over 10 percent for U.S. gas utilities and by more than 46 percent for Canadian utilities since 2012, indicating increased risk.
- Credit ratings have fallen slightly for U.S. gas utilities, indicating slightly increased risk, while average credit ratings have remained the same for Canadian utilities.
- The VIX (a measure of stock market volatility) has increased substantially as compared to 2012, although COVID-19 pandemic-related volatility has lessened from the peaks in 2020.

Figure 22: Comparison of Market Risk Indicators[198]

Description	2011	2012	2022 YTD	Risk Takeaway
P/E Ratios - US Gas Utilities	14.80	15.81	23.77	Decrease
M/B Ratios - US Gas Utilities	1.64	1.61	1.90	Decrease
30-Year Treasury Yield (US)	3.91%	2.92%	2.86%	Same
P/E Ratios - Canadian Utilities	21.11	23.72	22.49	Same
M/B Ratios - Canadian Utilities	2.18	2.72	1.82	Increase
30-Year Treasury Yield (Canadian)	3.29%	2.45%	2.69%	Increase
Beta Coefficients - US Gas Utilities	0.76	0.74	0.82	Increase
Beta Coefficients - Canadian Utilities	0.59	0.58	0.85	Increase
Credit Ratings - US Gas Utilities	A-	A-	BBB+	Increase
Credit Ratings - Canadian Utilities	A-	BBB+	BBB+	Same
VIX Index	24.20	17.80	25.85	Increase

[198] Source: Bloomberg Professional and S&P Capital IQ Pro. For purposes of this analysis, "US Gas Utilities" include every company identified by Value Line as a natural gas distribution utility, and "Canadian Utilities" include every publicly-traded Canadian utility company except for TransCanada.

Based on our qualitative assessment of the Company's risk environment, and our quantitative assessment of market risk indicators, we conclude that Enbridge Gas' risk profile has materially increased since 2012. Thus, according to the OEB's methodology for determining the Company's equity thickness, we conclude that a full fair return standard analysis is necessary.

SECTION 5:
FAIR RETURN STANDARD ANALYSIS

After determining that the Company's risk profile has materially changed since 2012, Concentric developed an analysis of the appropriate equity ratio for Enbridge Gas based on the principles of a fair return. Specifically, Concentric analyzed the equity ratios of four proxy groups of other North American utilities screened for risk characteristics similar to Enbridge Gas. Concentric reviewed three separate measures of the equity ratios of those similarly situated regulated utilities:

(1) the historical equity ratios maintained by comparable publicly-traded holding companies (to the extent applicable);

(2) the historical book equity ratios maintained by the gas operating subsidiaries of those holding companies; and

(3) the equity ratios authorized by the regulators of those gas operating subsidiaries.

Those measures provide relevant data from which to determine where, within a reasonable range, Enbridge Gas' deemed equity ratio should be set by the OEB, with the regulated operating company equity ratios being most applicable for purposes of assessing Enbridge Gas' regulated equity thickness.

As noted, Concentric analyzed four proxy groups. The bullet points below briefly summarize the companies included in each proxy group. The screening criteria used to select the proxy groups are described in more detail herein.

- Canadian Operating Companies ("Canadian OpCos"): This proxy group includes every investor-owned natural gas distribution utility in Canada, excluding the Company.
- Canadian Holding Companies ("Canadian HoldCos"): This proxy group includes every publicly-traded Canadian utility with an investment grade credit rating, excluding Enbridge Inc. (i.e., the parent company of Enbridge Gas) and TC Energy (due to the risk profile of the TransCanada Mainline).
- US Operating Companies ("US OpCos"): This proxy group includes the ten largest US natural gas distribution utilities, as measured by net utility plant, gas customers, and sales volumes.
- US Holding Companies ("US HoldCos"): This proxy group includes publicly traded companies identified by Value Line as natural gas utilities that pass a series of screening criteria designed to exclude companies that are dissimilar to Enbridge Gas.

The mean and median results for those proxy groups are provided in Figure 23 and Figure 24 respectively, below.

Figure 23: Summary of Comparative Analysis Results (Mean)[199]

Proxy Group	Gas Subsidiaries: Currently Authorized Equity Ratio	Gas Subsidiaries: 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	41.70%	42.80%	N/A
Canadian Holding Companies	47.53%	55.57%	41.28%
US Operating Companies	51.40%	53.38%	N/A
US Holding Companies	53.54%	54.92%	45.79%

Figure 24: Summary of Comparative Analysis Results (Median)

Proxy Group	Gas Subsidiaries: Currently Authorized Equity Ratio	Gas Subsidiaries: 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	40.50%	41.74%	N/A
Canadian Holding Companies	49.00%	54.30%	41.41%
US Operating Companies	51.00%	52.41%	N/A
US Holding Companies	53.50%	55.24%	46.38%

This evaluation of comparable regulated natural gas distribution utilities in the U.S. and Canada indicates that Enbridge Gas' current deemed equity thickness is low relative to its peer companies, despite Enbridge Gas falling in the middle of the spectrum of risk profiles. Taken together, the analyses support an equity ratio in the range of 40% to 45% for Enbridge Gas. Within that range, Concentric specifically recommends an equity ratio of no less than 42% for Enbridge Gas for the reasons discussed later in this report.

199 At the Holding Company level, authorized equity ratios are an average of the operating utilities held by the Holding Company.

SECTION 5(a):
PROXY GROUP SELECTION & RESULTS

1. Use of Proxy Company Analysis for Cost of Capital Determinations

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

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

> *Composition of the Proxy Group: In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*[200]

[200] Opinion No. 531, Order on Initial Decision, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45.

While the individual screens require modification based on the subject company to which proxy companies are being compared,[201] screening companies based on their risk characteristics increases both the comparability of the group and the confidence that the analyst (or regulator) can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that which we typically apply in cost of capital analyses to narrow the list of potential companies in order to identify natural gas utility companies that are risk appropriate for comparison to Enbridge Gas.

Given the unique characteristics of Enbridge Gas, and, in particular, the fact that it is one of the largest natural gas distribution utilities in North America and that it operates exclusively in Ontario, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of the range of reasonable equity ratios. That determination must be based on an assessment of Enbridge Gas' specific risks relative to the proxy group and informed judgment. For example, the National Energy Board (predecessor to the Canada Energy Regulator), in discussing the cost of capital for the TransCanada Mainline, stated, "[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences."[202] In other words, whereas a subject company of average risk relative to the proxy group potentially would warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk potentially would warrant an equity ratio above the mean or median result, and a company of lower risk potentially would warrant an equity ratio below the mean or median result.

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

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

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

2. Selection of Proxy Companies

As discussed above, Enbridge Gas is distinctive in that it is one of the largest natural gas distribution utilities in North America and operates exclusively in Ontario. Therefore, to determine a reasonable range of equity ratios for Enbridge Gas, Concentric studied data derived from four separate proxy groups: (1) the Canadian OpCo Proxy Group, (2) the Canadian HoldCo Proxy Group, (3) the US OpCo Proxy Group, and (4) the US HoldCo Proxy Group. The development of each proxy group is discussed in more detail below.

a) Canadian OpCo Proxy Group

The first proxy group (i.e., the Canadian OpCo Proxy Group) includes every investor-owned natural gas distribution utility in Canada, except for Enbridge Gas (to avoid the circularity that would otherwise occur). Figure 25 summarizes the ten companies that comprise the Canadian OpCo Proxy Group. By design, none of the companies in the Canadian OpCo Proxy Group is publicly traded, but rather each is an operating company of a utility holding company.

Figure 25: Canadian OpCo Proxy Group

Company
Apex Utilities Inc.
ATCO Gas
Energir (formerly Gaz Metro)
FortisBC Energy
Gazifere Inc.
Heritage Gas Limited
Liberty Utilities Gas New Brunswick
Pacific Northern Gas Ltd
Pacific Northern Gas Ltd (Fort St. John/Dawson Creek)
Pacific Northern Gas Ltd (Tumbler Ridge)

b) Canadian HoldCo Proxy Group

The next proxy group (i.e., the Canadian HoldCo Proxy Group) is comprised of publicly-traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly-traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Enbridge Inc. has been excluded because it is the parent company of Enbridge Gas. TC Energy (formerly TransCanada) has been excluded due to the risk profile of the TransCanada Mainline, which differs materially from natural gas distribution operations. The following six companies comprise the Canadian HoldCo Proxy Group:

Figure 26: Canadian HoldCo Proxy Group

Company	Ticker
Algonquin Power and Utilities Corp.	AQN
AltaGas Inc.	ALA
Canadian Utilities Limited	CU
Emera, Inc.	EMA
Fortis Inc.	FTS
Hydro One Ltd.	H

c) US OpCo Proxy Group

The US OpCo Proxy Group includes the ten largest regulated natural gas distribution utilities in the US as measured by net gas utility plant, number of gas distribution customers, and sales volumes. Specifically, Concentric used data from S&P Capital IQ Pro to rank every operating natural gas utility in terms of net gas utility plant, number of gas distribution customers, and sales volumes, with a ranking of one denoting the largest company by each measure. The ten operating natural gas utilities with the highest (closest to one) overall average ranking were included in the US OpCo Proxy Group. Figure 27 summarizes those ten companies:

Figure 27: US OpCo Proxy Group

Company
Southern California Gas Company
Consumers Energy Company
Northern Illinois Gas Company
DTE Gas Company
Consolidated Edison Company of New York, Inc.
The East Ohio Gas Company
Brooklyn Union Gas Company
Atlanta Gas Light Company
Columbia Gas of Ohio, Inc.
The Peoples Gas Light and Coke Company

d) *US HoldCo Proxy Group*

The last proxy group (i.e., the US HoldCo Proxy Group) is comprised of publicly-traded US natural gas distribution companies that would be considered by investors as generally comparable in risk to Enbridge Gas. To obtain companies of like risk, we performed a number of screens to develop a group of companies that are primarily engaged in the provision of regulated natural gas distribution utility service. Starting with the ten domestic companies that Value Line classifies as natural gas utilities, Concentric screened for companies that:

- **Have regulated net income that makes up greater than 60% of total income for the consolidated company**. This screen, in combination with the screen below regarding gas net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated gas operations. While rates in this proceeding are being set for Enbridge Gas' 100% rate-regulated gas distribution operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, in Concentric's experience, using a screening criterion of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group.
- **Have regulated gas net income that makes up greater than 60% of net income for the consolidated company's regulated operations**. Including only those companies that derive more than 60% of their regulated net income from regulated gas operations ensures that the proxy companies, like Enbridge Gas, derive the predominant share of their financial results from regulated gas segments. Similar to the regulated net income screen, the 60% regulated gas net income screen is not a "bright line," but rather is intended to balance the comparability of the proxy group with its overall size; and
- **Have an investment grade credit rating**. As noted earlier, Enbridge Gas has an "A" issuer and unsecured debt rating from DBRS and an "A-" corporate and unsecured debt credit rating from S&P. As credit ratings are based on the utility's business risk profile (including an assessment of its regulatory environment) and financial risk profile, companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that "it is reasonable to use the proxy companies' corporate credit rating as

a good measure of investment risk, since this rating considers both financial and business risk."[203] Concentric's credit rating screen selects gas utility companies with investment-grade credit ratings (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above), which reduces the need to adjust the results to account for any perceived differences in business or financial risk compared to Enbridge Gas. Further, selecting proxy companies that, like Enbridge Gas, have an investment grade credit rating ensures that the proxy companies are generally in sound financial condition. Because credit ratings consider business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.[204]

The following eight companies passed these screening criteria and comprise the US HoldCo Proxy Group:

Figure 28: US HoldCo Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

3. Proxy Group Business Risk Analysis

In order to further evaluate the comparability of the proxy group companies, Concentric examined the business risks of each company relative to Enbridge Gas. The purpose of this evaluation is to determine the extent to which the companies in each proxy group have similar risk profiles to Enbridge Gas (indicating that Enbridge Gas is of average risk, compared to the proxy group), or are

[203] See, e.g., Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.

[204] In a few instances, the credit rating of the publicly-traded holding companies largest subsidiary was used because the holding company was not independently rated by Moody's or S&P. For the companies in the proxy group, those instances were (1) New Jersey Resources Corporation, where Moody's A1 rating for New Jersey Natural Gas Co. was used, and (2) Northwest Natural Holding Company, where S&P's A+ rating and Moody's (P) Baa1 rating for Northwest Natural Gas Co. was used.

more or less risky than Enbridge Gas (indicating a need to potentially establish an equity thickness for Enbridge Gas that is above or below the mean of the groups).

Concentric focused on three primary risk characteristics – the degree of Energy Transition risk, the supportiveness of regulatory environments, and size.

a. Energy Transition

As discussed herein, the Energy Transition represents a fundamental transformation of the risk environment in which natural gas distribution utilities such as Enbridge Gas operate. Therefore, our comparison of the Company's business risk profile to those of the proxy companies begins with a comparison of the degree to which the Company and the proxy groups are exposed to Energy Transition risks.

As an initial matter, S&P observed in April 2020 that the Company's ESG risks are "similar to the broader industry." Specifically, S&P stated:

> *We view EGI's exposure to environmental, social, and governance-related risks as similar to the broader industry. EGI is a natural gas distributor. For natural gas network operators, environmental risks include gas leaks and explosions and emission of greenhouse gases (GHG), which can affect biodiversity. We believe EGI's environmental risk is consistent with the broader industry because the company continually monitors and replaces aging infrastructure to reduce the potential of gas leaks and explosions. In addition, the company also participates in the federal government's carbon levy program, to offset its GHG footprint in its gas distribution operations.*[205]

The Energy Transition places gas distribution utilities' long-term ability to earn a return of invested capital at risk as increasing costs must be collected from declining volumes. Accordingly, as a general matter, companies whose assets have more remaining book life and lower depreciation rates have more exposure to Energy Transition risks than companies whose assets have less remaining book life and higher depreciation rates. All else equal, relatively higher remaining book lives and/or relatively lower depreciation rates indicate that it will take longer for an investor to recover the return of invested capital, therefore increasing exposure to Energy Transition risks such as stranded asset risk and volumetric risk.

Generally, gas utilities (such as Enbridge Gas) and regulators (such as the OEB), have a variety of tools available to respond to the increasing risks posed by the Energy Transition. One such tool is

205 S&P Global Ratings, "Enbridge Gas Inc.," April 3, 2020, at 7.

increasing the deemed equity ratio in recognition of those increased risks. Another such tool is increasing depreciation rates, which may mitigate Energy Transition risks by allowing the gas utility to recover its invested capital more quickly.

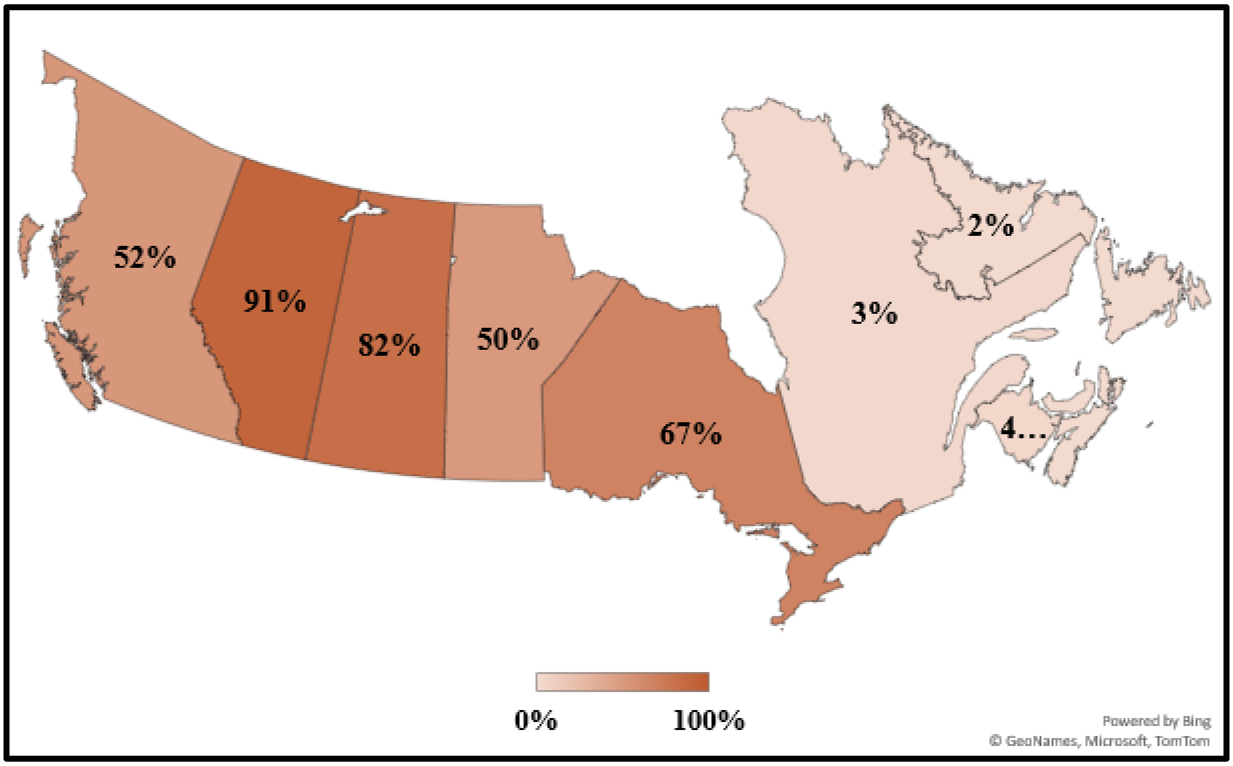
To evaluate the Company's degree of Energy Transition risk relative to the proxy groups, Concentric used reported gross plant, accumulated depreciation, and depreciation expense for the two most recent years for which data was available (i.e., 2020 and 2021) for each proxy company to calculate (1) remaining book life (i.e., net plant divided by depreciation expense), (2) total book life (i.e., gross plant divided by depreciation expense), and (3) percent depreciated (i.e., accumulated depreciation divided by gross plant). This analysis is provided in Schedule 2 and summarized in Figure 29 below.

Figure 29: Energy Transition Risk Comparison

	Remaining Life		Total Life		% Depreciated	
Proxy Group	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**
Canadian OpCo	22.21	18.69	31.48	27.96	29.88%	33.24%
Canadian HoldCo	22.64	21.45	34.05	32.16	33.44%	33.25%
US OpCo	28.07	28.27	38.88	38.72	28.90%	28.03%
US HoldCo	28.61	26.64	38.98	38.01	26.71%	28.96%
Enbridge Gas	**27.51**	**27.79**	**35.40**	**35.88**	**22.29%**	**22.56%**

As shown, the average remaining life of the Company's property is substantially longer than the Canadian OpCo, the Canadian HoldCo, and the US Holdco proxy groups and is generally consistent with the US OpCo proxy group. Additionally, the Company's assets are, on average, much less depreciated than the assets of any of the proxy groups. Therefore, this analysis suggests that the Company faces as much, if not more, Energy Transition risk than any of the proxy groups on average. Further, as shown in Figure 30, approximately two thirds of Ontario's residents use natural gas for space heating, which ranks third among all Canadian provinces. This means that the Company faces relatively higher risk than other Canadian gas utilities due to its exposure to customers that could leave its system via conversions to alternative fuels, including electrification. Further, the Company, unlike certain other Canadian utilities, operates exclusively as a gas distribution utility and does not provide electric utility services. As Moody's notes, "combination electric and gas distribution utilities are best positioned to absorb a decline in gas use because they can also benefit from the upside of electrification."[206] Therefore, due to its exclusive focus on natural gas operations, EGI faces higher risk than combination utilities such as ATCO.

Figure 30: Share of Residential Space Heating Provided by Natural Gas (2019)[207]



Concentric concludes that the Company faces Energy Transition risk that is greater than the proxy groups on average, and both the Company and the proxy companies face substantial Energy Transition risk because they engage in the provision of regulated natural gas distribution service.

206 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 9.

207 Source: Natural Resources Canada, Residential Sector, Table 21: Housing Stock by Building Type and Vintage. 2019 is the most recent year for which data is available.

b. Regulatory Environment

The ratemaking process in both the U.S. and Canada is premised on the principle that utilities must have the opportunity to earn a fair return on and of invested capital to provide incentives to investors to commit the capital required to ensure the provision of safe and reliable utility service. In that regard, a utility's regulatory environment is one of the most important factors considered by debt and equity investors when assessing a utility's risk.

Consider, for example, the credit rating methodologies established by Moody's and S&P. As discussed earlier, both credit rating agencies assign significant weight to the supportiveness of the regulatory environment when determining utility credit ratings. Specifically, Moody's places 25% weight on the utility's "regulatory framework" and another 25% weight on its "ability to recover costs and earn returns."[208] Similarly, S&P has opined that a "significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[209] Therefore, the supportiveness of the Company's regulatory environment relative to the proxy groups is an important factor in determining how the Company's overall risk profile compares to those of the proxy companies.

UBS, a prominent investment bank, ranks regulatory jurisdictions in the U.S. and Canada for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. Specifically, UBS places regulatory jurisdictions into five tiers based on the following equally weighted criteria: (1) whether commissioners are elected or appointed, (2) allowed returns relative to 10-year Treasury notes; (3) mechanisms that reduce regulatory lag, (4) rate and customer bill levels, (5) the tendency to settle or litigate rate cases, and (6) a subjective "investor friendliness" factor. Figure 31 compares UBS' ranking of the regulatory environment in which Enbridge Gas operates (i.e., Ontario) to the average ranking assigned to the regulatory environments in which the proxy companies operate. As shown, UBS ranked Ontario's regulatory environment in tier three out of five (with one being the best) in a December 2020 report.[210] UBS placed British Columbia in tier one, Nova Scotia in tier two, Newfoundland and Labrador and Prince Edward Island in tier three, and Alberta in tier four.

S&P also assesses the credit supportiveness of regulatory jurisdictions in the U.S. and Canadian

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208 Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, June 23, 2017, at 4.

209 Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

210 UBS Global Research, "North American Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020, at 5.

provinces. Specifically, S&P groups jurisdictions into tiers ranging from "credit supportive" to "most credit supportive." Figure 31 also compares S&P's ranking of the Ontario regulatory environment to the average ranking assigned to the proxy companies' regulatory environments.

Figure 31: Summary of UBS and S&P Regulatory Rankings[211]

Proxy Group	Average Regulatory Ranking	
	S&P	UBS
Canadian OpCo	Most Credit Supportive (Rank 1 of 5)	Tier 2 (Out of 5)
Canadian HoldCo	Very Credit Supportive (Rank 3 of 5)	Tier 3 (Out of 5)
US OpCo	Very Credit Supportive (Rank 3 of 5)	Tier 3 (Out of 5)
US HoldCo	Very Credit Supportive (Rank 3 of 5)	Tier 3 (Out of 5)
Ontario	Most Credit Supportive (Rank 1 of 5)	Tier 3 (Out of 5)

As shown, UBS ranked Ontario below the Canadian OpCo Proxy Group on average, and in line with the other three proxy groups. In contrast, S&P ranks the regulatory environment in Ontario in line with the Canadian OpCo group and above the other proxy groups. However, as discussed previously, S&P notes that all regulation is credit supportive, and that its rankings are only a matter of degree:

> *The categories are an important starting point for assessing utility regulation and its effect on ratings. They are all credit-supportive to one degree or another, as all utility regulation tends to sustain credit quality. The presence of regulators, no matter where on the spectrum of our assessments, reduces business risk and generally supports utility ratings. We therefore designate all these jurisdictions from credit supportive to most credit supportive, and these vary only in degree.*[212]

Therefore, while S&P does differentiate between the supportiveness of the Company's regulatory jurisdiction relative to those of the proxy groups, we conclude that S&P views that differential as slight. Additionally, while S&P maintained Ontario's rank as "Most Credit Supportive" (i.e., the highest tier) in its June 2021 update of its regulatory rankings, S&P identified the following as a "notable development":

> *Major rate case parameters such as ROE are formula-driven, and regulated capital structures have remained consistent for years, promoting predictability. However, these parameters have become the lowest in the Canadian provinces, which could weaken*

211 Sources: UBS Global Research, "North American Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020; S&P Global RatingsDirect, "Updated Views on North American Utility Regulatory Jurisdictions – June 2021," June 29, 2021.

212 S&P Global RatingsDirect, "Updated Views on North American Utility Regulatory Jurisdictions – June 2021," June 29, 2021, at 2.

> *investment in regulated utilities. Coupled with the OEB's report on COVID-19 pandemic cost recovery, we believe the interests of various stakeholders have become unbalanced.*[213]

Concentric notes that the Company benefits from a variety of constructive ratemaking mechanisms (e.g., alternative ratemaking processes, deferral and variance accounts, etc.). In addition, the Company is proposing to implement SFV rate design in this proceeding. Similar mechanisms, however, are widely available to the proxy companies. Specifically, Schedule 3 provides summaries of several relevant ratemaking practices for the operating subsidiaries in each of the four proxy groups, including (1) their use of alternative ratemaking mechanisms such as formula-based ratemaking or multi-year rate plans, (2) whether the jurisdiction relies on historical or forecast test years for ratemaking purposes, and (3) the ratemaking mechanisms available to the utility (e.g., fuel cost recovery, revenue decoupling, capital cost recovery, etc.).

As shown in Schedule 3 and as summarized in Figure 32, Enbridge Gas and the operating utilities included in each of the four proxy groups have test year conventions, rate plans, and various adjustment clauses and cost recovery mechanisms that provide risk mitigation. Concentric notes that for the general service rate classes, Enbridge Gas currently has a revenue neutral mechanism that protects the customer and the Company against changes in average use but offers no protection due to weather conditions. Enbridge Gas is proposing to implement SFV rate design to mitigate volumetric risk as part of this rate application. Should the SFV be approved, and until the SFV is fully implemented, Enbridge Gas is proposing to establish a revenue neutral mechanism to protect the customer and the Company against volumetric risk in the interim. This mechanism will record the revenue impact due to volumetric forecast variance, resulting from changes in average use per customer and weather experienced during the year for the general service rate classes.

213 *Id.*, at 7.

Figure 32: Summary of Regulatory Mechanisms for Proxy Groups[214]

	Percentage of Companies Operating in Juridictions With …				
Proxy Group	Formula-Based Ratemaking or Multi-Year Rate Plans	Fully or Partially Forecast Test Years	Full or Partial Decoupling	Capital Cost Trackers	Conservation Programs
Canadian OpCo	44%	78%	67%	83%	50%
Canadian HoldCo	56%	61%	61%	67%	39%
US OpCo	40%	80%	100%	80%	80%
US HoldCo	42%	42%	88%	73%	50%
Enbridge Gas	Yes	Fully	Partial	Yes	Yes

Concentric notes that many of the regulatory jurisdictions in which the proxy companies operate tout the supportiveness of the ratemaking mechanisms they offer. For example, Staff at the New York Public Service Commission (i.e., the regulator for Consolidated Edison Company of New York and Brooklyn Union Gas Company, two companies in the US OpCo Proxy Group) recently opined that "New York provides its utilities with fully forecasted test years, fuel cost recovery, multi-year rate plans, revenue decoupling, and capital cost recovery mechanisms. We believe these factors provide New York utilities with an advantage over utilities operating in other jurisdictions."[215] However, despite these protections, Central Hudson Gas & Electric Corporation (i.e., a utility regulated by the New York Public Service Commission) was recently downgraded by Moody's in part because its authorized equity ratio was reduced from 50 percent to 48 percent in the third year of its three year rate plan. Specifically, Moody's noted that several factors "will contribute to the weakness in financial metrics including growth in regulatory assets combined with a reduction in regulatory liabilities and a reduction in equity capital from 50% to 48% over the next 3 years and a large ongoing capital program."[216]

Further, the Massachusetts DPU (i.e., the regulator for New England Natural Gas Company, an operating subsidiary of one of the companies in the Canadian HoldCo Proxy Group) recently found:

214 Information is not readily available for several of the companies in the Canadian OpCo proxy group. The percentages shown in the table are based on the number of companies with each regulatory mechanism divided by the number of companies for which information could be obtained.

215 New York Cases 20-E-0428 and 20-G-0429, Prepared Testimony of the Staff Finance Panel, at 148.

216 Moody's Investors Service, "Rating Action: Moody's Downgrades Central Hudson Gas & Electric to Baa1; Stable Outlook," September 22, 2021.

> *In particular, the Department established in this Order a PBRM that, among other things, allows the Company to implement an annual rate adjustment to provide revenue support for expenses and capital investment. The resulting more timely and flexible cost recovery serves to reduce a company's risks. Further, we consider NSTAR Gas's reconciling mechanisms. The Department previously approved a revenue decoupling mechanism for NSTAR Gas in D.P.U. 14-150, at 16-23, and has directed all gas and electric distribution companies to file for revenue decoupling in a base distribution rate proceeding. The Department has found that revenue decoupling mechanisms can act to reduce the variability of a company's revenues and, consequently, reduces its financial risks. In addition to the revenue decoupling mechanism, the Department considers NSTAR Gas's use of reconciling mechanisms to recover certain costs, dollar-for-dollar, outside of base distribution rates. The Company presently has in place fully reconciling mechanisms for a range of expenses, including GSEP, gas costs, energy efficiency costs, pension/PBOP expense, Attorney General consultant costs, and supply-related bad debt. As a result of this Order, NSTAR Gas will retain these reconciling mechanisms. The use of these reconciling mechanisms covering a significant portion of the Company's expenses combined with elements of the PBR Plan results in lower risk for NSTAR Gas than otherwise would be the case.*[217]

On the basis of the above, Concentric concludes that Enbridge Gas is comparable to the proxy companies, assuming that its existing deferral and variance accounts continue as requested, and that its rate design proposals are approved, in the upcoming proceeding.

c. Size

Concentric also considered the size of Enbridge Gas relative to the proxy groups. By most measures (e.g., sales volumes, revenues, net utility plant, etc.), Enbridge Gas is one of the largest natural gas distribution utilities in North America. Academic literature recognizes that, all else equal, investors have higher return requirements for investments in smaller companies than for investments in larger companies. Moody's credit rating methodology, for example, identifies the size and diversity of utility operations as a distinguishing factor in utility risk profiles:

> *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 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*

[217] Massachusetts Department of Public Utilities, D.P.U. 19-120, Order, at 404-405.

> *economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.*[218]

While the Company is quite large as measured by customers, sales, assets, etc., its operations are limited to natural gas distribution in Ontario, Canada. This lack of regulatory and geographic diversity partially mitigates the risk reductions created by the Company's large size. For example, as S&P notes:

> *EGI lacks geographic and regulatory diversity. EGI operates only in Ontario. It is the largest gas distributor in Ontario and serves virtually all of Ontario with approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, making it reliant on the Ontario Energy Board (OEB) and its regulation to sustain its credit quality.*[219]

Additionally, we note that the OEB has previously rejected the argument that a utility's size has a bearing on its risk. Prior to 2007, the OEB had deemed capital structures for regulated electricity distributors based on their size. Figure 33 summarizes the capital structures authorized by the OEB in 2006 (i.e., just prior to the OEB's decision to deem a single capital structure for all regulated electricity distributors).

Figure 33: Deemed Capital Structures for Ontario's Distributors in 2006[220]

Rate Base	Deemed Capital Structure	
	Debt	**Equity**
>$1.0 billion	65%	35%
$250 million – $1 billion	60%	40%
$100 million – $250 million	55%	45%
<$100 million	50%	50%

However, in the December 20, 2006 Report of the OEB on the Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, the OEB changed its policy and deemed a single capital structure of 40% equity and 60% debt for every electric distributor it regulated.[221] The OEB noted in its decision that several parties to the proceeding argued that small distributors faced greater business risk than large distributors because they may face greater load concentration risk.

218 Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 19.
219 S&P Global Ratings, Enbridge Gas Inc., February 1, 2022, at 2.
220 Report of the Board on the Cost of Capital and 2nd Generation Incentive Regulator for Ontario's Electricity Distributors, December 20, 2006, at 4.
221 *Id.*, at 5.

The OEB dismissed these arguments, finding that load concentration risk is not necessarily related to utility size. The OEB concluded that "size is not a key determinant of, or proxy for, risk."[222] The OEB elaborated:

> *A distributor, regardless of size, when planning and making decisions to manage its business risk, will organize its financing in line with its business needs.*
>
> *The Board concludes that utility size no longer represents an accurate proxy for risk. As a result, there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size.*[223]

Given the Company's lack of geographic diversity and the OEB's prior findings with regard to size and risk, Concentric finds that Enbridge Gas' larger size relative to the proxy companies does not warrant an adjustment to our recommended equity thickness.

222 *Id.*, at 7.
223 S&P Global RatingsDirect, Enbridge Gas Inc., January 19, 2021, at 3.

4. Proxy Group Financial Risk Analysis

a. Equity Ratio Comparison

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

The proxy group mean and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for Enbridge Gas, after consideration of differences in risk profiles between Enbridge Gas and the proxy group. Specifically, the mean is "generally the best measure of central location for purposes of statistical inference,"[224] while also being at risk of being "unduly influenced by extreme observations."[225] The median, or middle point of a set of observations at which half of the set of observations are above it and half and below it, is not subject to the same distortion due to extreme observations.[226] Figure 34 and Figure 35 summarize the mean and median results, respectively, in tabular format for the four proxy groups. Schedule 4 provides the underlying analysis

Figure 34: Proxy Group Equity Ratios (Mean)

	Gas Subsidiaries		Holding
Proxy Group	Currently Authorized Equity Ratio	2-Year Avg. Book Equity Ratio	Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	41.70%	42.80%	N/A
Canadian Holding Companies	47.53%	55.57%	41.28%
US Operating Companies	51.40%	53.38%	N/A
US Holding Companies	53.54%	54.92%	45.79%

224 Keller and Warrack, Statistics for Management and Economics, 5e ed., Duxbury Thompson Learning, 2000, at 92.
225 *Ibid*.
226 *Id*., at 93.

Figure 35: Proxy Group Equity Ratios (Median)

Proxy Group	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	40.50%	41.74%	N/A
Canadian Holding Companies	49.00%	54.30%	41.41%
US Operating Companies	51.00%	52.41%	N/A
US Holding Companies	53.50%	55.24%	46.38%

As shown in Figure 36 and Figure 37, Enbridge Gas' deemed equity ratio of 36% is far lower than the average and median equity ratios for all four proxy groups and all three analytical approaches. The mean and median equity ratios at the operating company level exceed 40% for all four proxy groups and all three analytical approaches. Enbridge Gas' deemed equity ratio is 4.50 to 19.24 percentage points below those of each group, depending on the proxy group and analytical approach employed.

Concentric notes that none of the companies in any of the proxy groups had a lower equity ratio than Enbridge Gas. The three companies with authorized common equity ratios that are closest to Enbridge Gas are ATCO Gas, Energir, and FortisBC Energy, with authorized common equity ratios of 37.0%, 38.5%, and 38.5%, respectively. Energir also has a material amount of preferred equity in its authorized capital structure. Credit rating agencies often treat preferred equity as 50% equity and 50% debt.[227] Therefore, in Figure 36, we adjusted Energir's authorized common equity ratio to include 50% of its preferred equity.[228]

227 The equity content that credit rating agencies ascribe to hybrid instruments such as preferred equity depends on the specific terms of the preferred equity issuance. However, generally, credit rating agencies treat preferred equity as 50% equity and 50% debt. For example, S&P Global Ratings notes that it classifies "ATCO's preferred stock and subordinated notes as hybrid securities with intermediate equity content (50%)" in a full analysis of ATCO Ltd. Published August 31, 2021. See also RBC Dominion Securities Inc., "A Guide to Preferred Shares," April 2018, or http://sellsidehandbook.com/2018/12/06/preferred-shares-primer/.

228 Please note that none of the proxy group results reflected in Schedule 4 includes preferred equity. Figure 35 above is for informational purposes only, although we note that the average adjusted equity ratio of the three indicated companies is consistent with the low end of our recommended range of equity ratios for Enbridge Gas.

Figure 36: Adjusted Equity Ratios of ATCO Gas, FortisBC Energy, and Energir[229]

Company	Common Equity	Preferred Equity	Adjusted Equity
ATCO Gas	37.00%	0.00%	37.00%
FortisBC Energy	38.50%	0.00%	38.50%
Energir Inc.	38.50%	7.50%	42.25%
Average	38.00%	2.50%	39.25%

b. Assessment of Credit Metrics

As discussed previously, financial risk is also measured through other credit metrics, such as the ratio of FFO/Debt and Debt/EBITDA, as well as interest coverage ratios that compare EBITDA and FFO to interest payments on long-term debt. While the Company is rated by S&P (and, therefore, S&P reports the aforementioned metrics for the Company), S&P's rating incorporates the effect of the Company's non-regulated operations. Therefore, as discussed in Section 4(c): Financial Risk, Concentric calculated stand-alone regulated operations credit metrics for the Company based on filings with the OEB that reflect only its regulated operations. Those calculated credit metrics for the Company were then compared to S&P's reported credit metrics for the proxy companies. If a particular proxy company was not rated by S&P, or if S&P did not report credit metrics for a particular proxy company, that proxy company was excluded from this analysis. Credit metrics for the Canadian OpCo Proxy Group are listed as "N/A" because an insufficient number of companies in that proxy group are rated by S&P to produce meaningful results.[230]

Figure 37 (also see Schedule 1) summarizes the key credit metrics for Enbridge Gas and the average credit metrics for the companies in each proxy group. The calculated S&P credit metrics for Enbridge Gas in 2021 are generally weaker than the proxy companies, although its FFO/Debt percentage and Debt/EBITDA metrics are better than those of the Canadian HoldCo group. All of Enbridge Gas' ratios are weaker than the average credit metrics for the US OpCo and the US HoldCo Proxy Groups. Compared to the Canadian HoldCo Proxy Group, Enbridge Gas has a higher debt to capital ratio, a

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229 FortisBC Energy is currently before the BCUC requesting an increase in its deemed common equity ratio to 45%. Likewise, Energir is currently before the Regie requesting an increase in its deemed common equity ratio to 43%, with no preferred equity included in the regulated capital structure.

230 Of the companies in the Canadian OpCo Proxy Group, S&P only provides the studied credit metrics for Energir Inc., and those credit metrics include electric distribution operations in Vermont and gas distribution operations in Quebec and Vermont.

weaker EBITDA interest coverage ratio and FFO to cash interest coverage ratio, and stronger FFO/Debt and Debt/EBITDA ratios.

Figure 37: 2021 S&P Credit Metrics Comparison

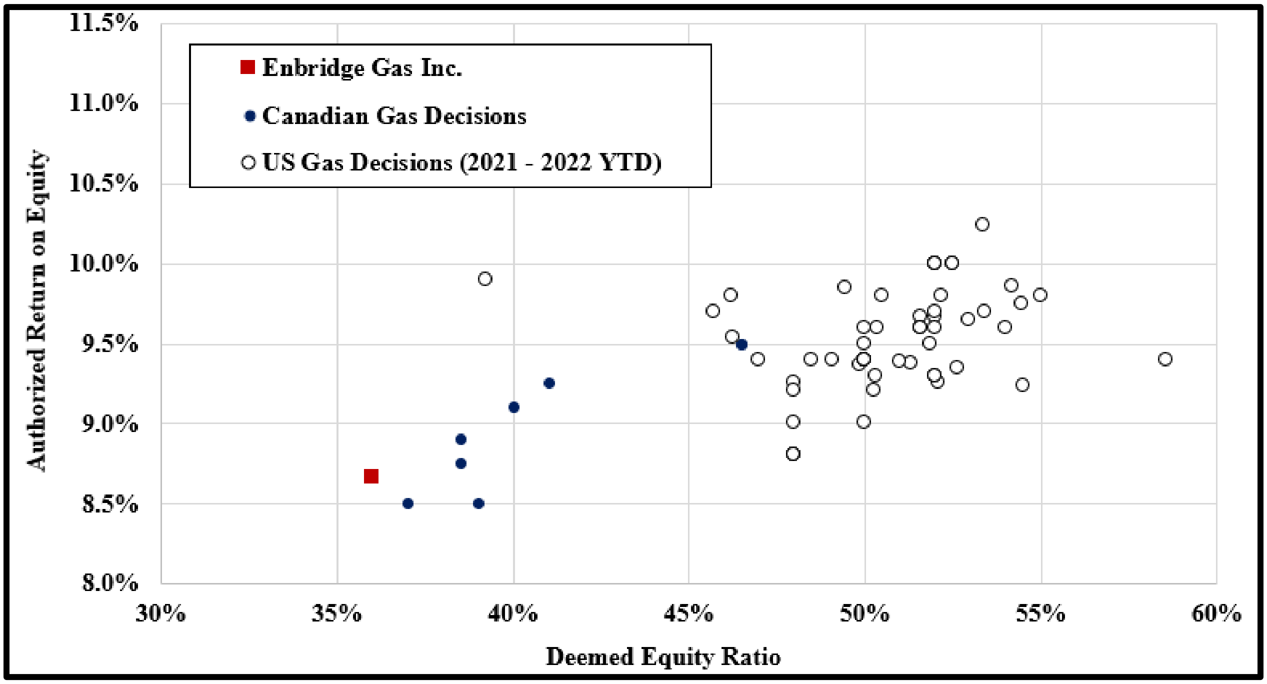
Company / Proxy Group	Debt to Capital Ratio	EBITDA Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Enbridge Gas Inc. (S&P)	49.7%	4.29	4.33	12.4%	6.21
Enbridge Gas Inc. (Reg-only)	64.0%	2.36	3.93	12.2%	5.92
Canadian OpCo Average [1]	N/A	N/A	N/A	N/A	N/A
Canadian HoldCo Average	58.0%	4.08	4.20	11.5%	6.53
US OpCo Average	49.7%	8.34	10.18	19.3%	4.56
US HoldCo Average	57.8%	6.94	5.51	14.2%	5.75

Notes:
[1] Insufficient companies in this proxy group are rated by S&P to produce meaningful results.

c. Weighted Returns on Equity

As shown in Figure 38, the Company's currently authorized ROE (8.66%) and equity ratio (36.0%) are both among the lowest for North American gas distribution utilities. As a result, the Company's weighted authorized return on equity (3.12%) is substantially below that of other Canadian operating gas utilities (3.94% on average) and recent U.S. gas decisions (4.83% on average).

Figure 38: Authorized Returns and Equity Ratios for EGI vs. North American Gas Utilities



d. Proxy Group Financial Risk Analysis Conclusion

Enbridge Gas' deemed equity ratio of 36% is far lower than the average and median equity ratios across all of Concentric's analytical approaches, and none of the companies in any of the proxy groups has a lower equity ratio than Enbridge Gas. Furthermore, this higher degree of financial risk is not offset by consistently better credit metrics, lower business risk, or other factors. Therefore, Concentric concludes that Enbridge Gas has greater financial risk than the average comparable company.

SECTION 5(b):
GAS VS. ELECTRIC RISKS

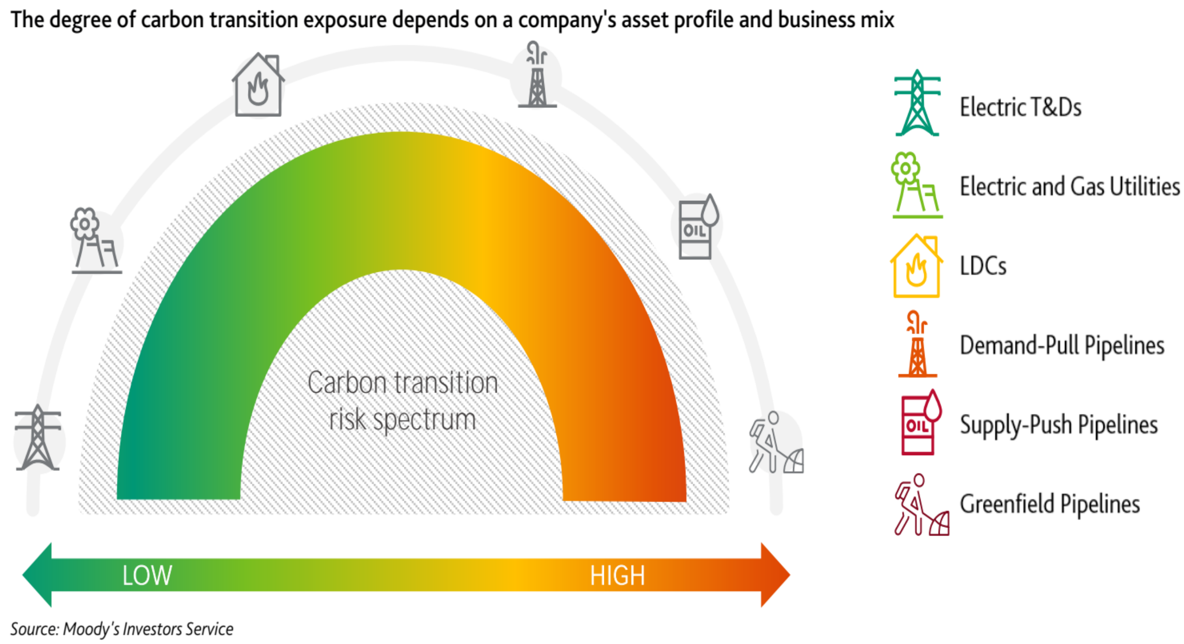
As discussed previously in our report, electricity distributors in Ontario are currently authorized a 40% deemed equity ratio, compared to Enbridge Gas's 36% equity ratio. Since, all else equal, a lower equity ratio indicates lower risk, Concentric evaluated the relative risks of gas LDCs and electric distribution utilities to assess whether the risk relationship between gas and electric utilities has shifted over time.

As also discussed previously, several Canadian provinces and U.S. states (as well as many local municipalities in both countries) have implemented policies that either establish targets for reducing carbon emissions by a specific percentage within a certain timeframe, or that provide financial incentives to customers for switching from natural gas and other fossil fuel sources to electricity. These policies jeopardize the long-term viability of the natural gas industry and raise concerns about whether gas utilities will be able to recover investments in long-lived assets. In addition, the potential for a "death spiral" for natural gas utilities has increased relative to 2012. If existing customers leave the distribution system, there are fewer remaining customers across which to spread the fixed costs of the distribution system, thereby causing rates to increase for those remaining customers and further contributing to the downward spiral. While this situation may take many years to unfold, it is no longer speculative and the risk to gas LDCs and investors is more immediate because the planning horizon for regulated utilities is long-term in nature.

In a September 2020 report, Moody's concluded that "long-term challenges to natural gas infrastructure are increasing."

According to Moody's, the degree of carbon transition exposure depends on a company's asset profile and business mix. Figure 39 below shows that gas LDCs are considered to have higher carbon transition risk than either electric T&D companies or combination electric and gas utilities.

Figure 39: Carbon Transition Risk Spectrum[231]



The Moody's report also reached the following conclusions regarding the relative risk of gas distribution companies versus electric utilities:[232]

- Company-specific factors to determine credit impact: Demand-pull pipelines and **LDCs will be most sensitive** to the aforementioned geographical influences, such as local and state politics, weather characteristics and relative consumer costs.

- Political and strategic agendas impact LDC growth in some areas: The political and legislative push for lower carbon emissions will impact more than just the fuel source of electric generation units. **For the gas sector, decarbonization goals are more disruptive than renewable portfolio standards because the latter typically affects only power generation, whereas mandates to reduce emissions affect all fossil-fuel infrastructure.** In some pockets of the US, even local distribution companies (LDCs) are facing early-stage challenges to sales growth, where limited upstream expansion for supply or local restrictions on new gas services will have a greater impact on the business in the coming years.

- Pace of transition depends on technology, related costs and ultimately public policy: Certain technological advancements, including the prolific use of RNG or hydrogen gas blending,

[231] Moody's Investors Service, "Shifting environmental agendas raise long-term credit risk for natural gas investments,", September 30, 2020, at 10.
[232] *Ibid*.

could help to support the use of existing natural gas infrastructure, whereas competing technologies such as battery storage and hydrogen gas storage for electric generation could accelerate electrification efforts and the decline of gas assets.

In either case, the ability of consumers to absorb the cost of implementing any such changes will likely be a key factor in determining the pace and magnitude of asset replacement. **Full decarbonization efforts aimed at achieving net-zero emissions will likely come at a hefty cost**, ultimately to be borne by utility customers.

In its January 2021 report on the gas industry, Wells Fargo Securities also commented on the relative risk of gas and electric utilities and concluded:

> ***While the jury is still out as to whether a sub-sector with the word "gas" in its name can find favor (or at least not be penalized) in an ESG world,*** *we think the LDC group enters 2021 on solid fundamental ground.*[233]
>
> *Taking into account the solid fundamental backdrop and the considerations around de-carbonization and ESG risk,* ***we think the gas utilities should trade at a modest discount to electric utilities, all else equal.*** *We think a ~5% discount is reasonable and that anything beyond 10% would represent an attractive sub-sector entry point. At the end of 2020, the LDCs traded at an 8% discount to Regulated Electric peers, which compares to the 10-year median of [a] 10% premium.*[234]

Concentric examined financial and valuation measures to evaluate the relative risk of the natural gas distribution and electric utility sectors, including: 1) forward P/E ratios, and 2) Beta coefficients. We compared these measures for the natural gas LDC proxy group companies and the Value Line Electric Utility universe in 2021 versus the same measure in 2012. As discussed in this section of the report, Concentric's analysis demonstrates that investment risk (which includes both business risk and financial risk) for natural gas distribution companies has increased relative to electric utilities. Whereas gas distributors were traditionally viewed as having somewhat lower risk profiles than electric utilities, now the opposite is true, with investors perceiving higher risk for gas distributors as compared to electric utilities. This supports our recommendation that the deemed equity ratio for EGI should increase, particularly when considered in the context of the OEB's deemed equity ratio for electric distributors at 40%.

233 Wells Fargo Securities, LLC, "Gas Utilities 2021 Outlook: Solid Fundamentals Provide Backstop, ESG/Electrification Questions Linger," January 6, 2021, at 2.

234 *Id.*, at 6.

Beta: Beta is a measure of risk for equity investors. In particular, Beta measures the systematic or market risk that cannot be diversified away by an investor holding a diversified portfolio. In the Capital Asset Pricing Model ("CAPM") method, the Beta coefficient is multiplied by the market equity risk premium to derive the risk premium for a particular company or group of companies above the risk-free rate. For regulated utilities, Betas have traditionally been below the market average of 1.0, reflecting the lower risk nature of utility operations. However, since January 2020, Beta coefficients for regulated utility holding companies have increased significantly above historical average levels as utility stocks have traded much more in line with the broader market. Figure 40 below demonstrates that five-year weekly Beta coefficients from Bloomberg for gas distributors are currently somewhat lower than for electric utilities but have increased to a greater degree since 2012.

Figure 40: Bloomberg Beta Coefficients

	2012	2022	% Change
Canadian Proxy Group	0.5808	0.8571	47.6%
U.S. Gas Proxy Group	0.6786	0.8132	19.8%
U.S. Electric Utility Universe ex-PG&E	0.7272	0.8609	18.4%

These analyses demonstrate that gas distribution utilities are, on average, trading at a discount to their electric utility peers. This shift occurred in the second half of 2018, which is consistent with the timing of credit rating agencies implementing ESG criteria and with certain institutional investors and pension funds adopting more stringent limits or restrictions on their ability to own shares in fossil-fuel companies that contribute significantly to higher carbon and greenhouse gas emissions. Such companies are now viewed with some degree of skepticism by many investors, even though the near-term fundamental growth prospects for those companies remains intact. Over the longer-term, however, gas distributors are challenged to continue to add customers in the face of electrification efforts in many jurisdictions in both Canada and the U.S. This risk is substantially higher than in 2012 and supports our recommendation to increase the deemed common equity ratio for Enbridge Gas to compensate investors for the Company's higher risk profile relative to electric utilities.

SECTION 5(c):
THE RELEVANCE OF U.S. DATA

When establishing authorized costs of capital, Canadian regulators have long grappled with the relevance of data from U.S. utilities. The OEB has previously found that U.S. data is relevant to its cost of capital determinations. Specifically, in its 2009 Cost of Capital Report, the OEB noted:

> *[T]here was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed.*[235]

After discussing the positions of the various parties to that proceeding, the OEB concluded:

> *The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*
>
> *Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.*[236]

The OEB is one of a number of Canadian utility regulators that have accepted the use of U.S. data or U.S. proxy groups. For example, in its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. The NEB appears to view U.S. market returns as valuable information in establishing the cost of capital for Canadian utilities. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated

[235] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 21-22.
[236] *Id.*, at 23.

from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.[237] Importantly, the NEB also found that the regulatory regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries, stating:

> *The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.*[238]

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

> *In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.*[239]

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

> *The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.*

237 *Id.,* at 66-72.
238 *Ibid.*
239 British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 16.

And,

> *[I]n the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.*[240]

However, more recently, in a 2016 proceeding involving Ontario Power Generation ("OPG"), the OEB noted that both Concentric (presenting information on behalf of OPG) and the Brattle Group (presenting information on behalf of the OEB Staff) should have made adjustments to the comparator group data "to account for the substantially lower common equity ratios allowed regulated utilities in Canada." [241]

In considering this matter in this report, Concentric observes that allowed equity ratios for U.S. utilities generally remain higher than deemed equity ratios for Canadian utilities. However, this wide differential is not currently explained by differences in risk. Rather, Canada and the U.S. are both part of an integrated North American capital market and independent, third-party evidence from both equity and debt investors makes clear that investors do not perceive meaningful risk differentials between regulated utility investments in the two countries. The subsections that follow discuss evidence regarding the relative risks of regulated utility investments in Canada and the U.S. from (1) equity analysts, (2) credit rating agencies, (3) merger and acquisition activity, and (4) macroeconomic indicators.

1. Equity Analyst Views

Concentric's experience suggests that equity analysts perceive the U.S. and Canada as part of an integrated market for capital. This is demonstrated by a March 2019 report by equity analysts at Scotiabank indicating that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> *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)*

[240] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage I), Decision, May 10, 2013, at 20.

[241] Ontario Energy Board, Decision and Order EB-0216-0152, Ontario Power Generation Inc. , December 28, 2017, at 109.

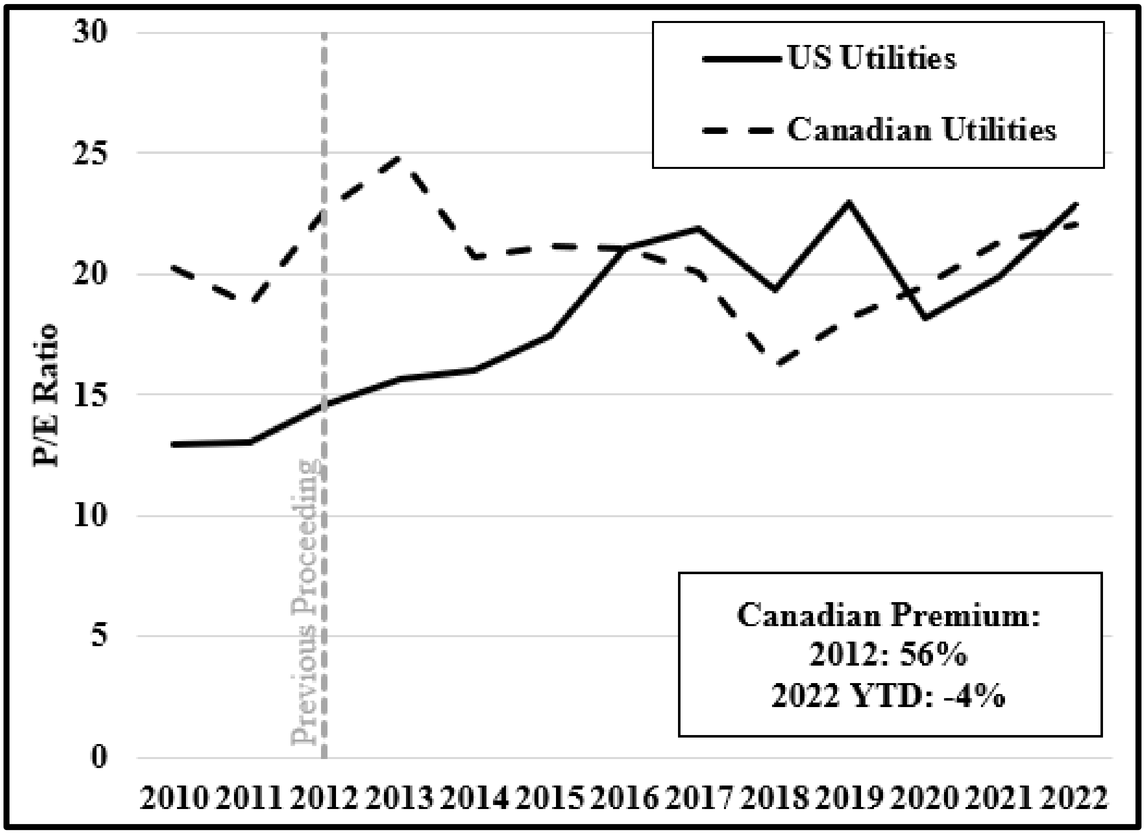
> *as well as to strong earnings growth in part due to M&A. As shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a 3x discount.*[242]

As noted, Scotiabank's report was published in March 2019. As a test of Scotiabank's conclusions, we have updated the P/E ratio valuation analysis Scotiabank conducted. That updated analysis is shown in Figure 41. As shown, this analysis validates Scotiabank's findings. Specifically:

- Canadian utilities traded at a substantial P/E ratio premium to U.S. utilities in the early 2010s.
- The valuation of Canadian utilities declined substantially relative to U.S. utilities over the 2010-2022 timeframe. Specifically, Canadian utilities traded at an approximately 56 percent premium to U.S. utilities in 2012, an approximately 21 percent discount to U.S. utilities in 2019, and are trading at a slight discount (i.e., approximately 4 percent) to U.S. utilities so far in 2022.
- Scotiabank accurately predicted the convergence of U.S. and Canadian utility valuations.

[242] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9.

Figure 41: P/E Ratios of Canadian and US Utilities[243]



Scotiabank went on to note the increasingly interconnected nature of U.S. and Canadian utility investments:

> *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.*[244]

Scotiabank is not the only equity analyst who perceives the regulatory environments in the U.S. and

[243] Source: Bloomberg Professional. Based on the analysis developed by Scotiabank, Canadian utilities in this figure include AQN, CU, EMA, FTS, and H, and US utilities include PNW, AEE, WEC, CMS, CNP, and NI. Scotiabank also included SCG, GAS, and WR in its analysis, however those utilities have been excluded from this figure as they have each been acquired after Scotiabank's analysis.

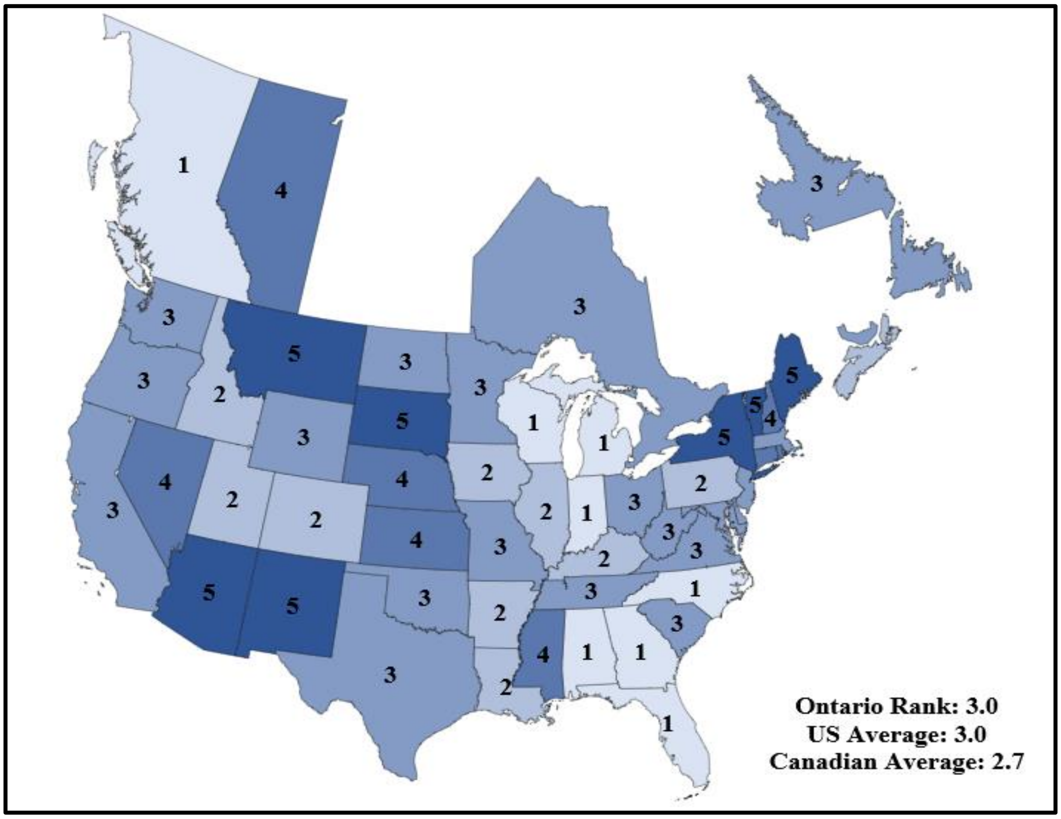
[244] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9.

Canada as generally comparable.

2. Credit Rating Agency Perspectives

As noted earlier, UBS places regulatory jurisdictions in the U.S. and Canada into five tiers (with tier 1 being the best) for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. As shown in Figure 42, UBS ranks Ontario slightly below the average ranking of all Canadian jurisdictions covered by UBS (i.e., tier 2.7) and in line with the average ranking of all US jurisdictions (i.e., tier 3.0).

Figure 42: UBS Regulatory Rankings (1 = Best, 5 = Worst)



3. Credit Rating Agency Perspectives

Like equity analysts, credit rating agencies have commented on the regulatory environments in which U.S. and Canadian utilities operate. For example, in a September 2013 report, Moody's explained its changing view on the relative risk of U.S. and Canadian utilities as follows:

> *Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US regulatory environment.*

> *Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.*[245]

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

- "We believe that many US regulatory jurisdictions have become more credit supportive of utilities over time and that the assessment of the regulatory environment in the US that has been incorporated in the ratings may now be overly conservative."[246]
- "While we had previously viewed individual state regulatory risks for US utilities as being higher than utilities in most other developed countries (where regulation usually occurs at the national level), we have observed an overall decrease in regulatory risk in the US."[247]
- "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."[248]
- "We believe the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states while balancing the needs of the state's commercial, industrial and residential utility customers."[249]
- "A comparison of key financial ratios used under the Regulated Electric and Gas Utilities Rating Methodology in rating utilities across developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan) shows that US regulated utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers."[250]

To our knowledge, S&P has not opined on the relative risks of the Canadian and U.S. regulatory

245 Moody's Investors Service, Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation, September 23, 2013, at 1.
246 *Id.*, at 4.
247 *Ibid.*
248 *Ibid.*
249 *Ibid.*
250 *Id.*, at 5.

environments as directly as Moody's. However, as noted previously, S&P does assess the credit supportiveness of regulatory jurisdictions in the U.S. and Canadian provinces, ranking them all credit supportive (on a scale from "credit supportive" to "most credit supportive").[251] In this ranking system, S&P categorizes Ontario as "most credit supportive." S&P indicates, however, that all regulation is credit supportive, and that its rankings between jurisdictions are only a matter of degree.

4. Merger & Acquisition Activity

Utility merger and acquisition ("M&A") activity has been extensive over the past two decades, creating fewer but larger utility enterprises. One result of this trend is that cross-border ownership of utility companies has increased. To evaluate the degree of financial integration in the utility industry, we examined cross-border utility investment since 2000. Our research focused on transactions where a U.S. utility acquired a Canadian utility or vice versa. We excluded acquisitions of discrete assets, such as generation facilities, renewable assets, electric and gas transmission assets, etc. We also excluded transactions that were not completed. Since 2000, we identified 22 transactions where a Canadian utility acquired a U.S. utility and three where a U.S. utility acquired a Canadian utility. In this same period, two U.S. companies sold their Canadian utility assets (Aquila in 2003 and Kinder Morgan in 2007). Figure 43 summarizes these M&A transactions.

[251] The U.S average includes the ranking of Federal Energy Regulatory Commission (ranked by S&P as "most credit supportive"); the New Orleans City Council (ranked by S&P as "very credit supportive") and the Railroad Commission of Texas (ranked by S&P as "highly credit supportive"). For ease of presentation, these three regulatory entities are not presented in this figure.

Figure 43: Cross-Border Utility Acquisitions

Buyer	Target	Deal Value (US$Millions)	Year
Canadian Buyers Acquiring U.S. Utilities Since 2000			
Algonquin Power & Utilities	Kentucky Power	$2,646	Pending
ENMAX Corporation	Emera Maine	$959	2019
Liberty Utilities Co.	St. Lawrence Gas Company, Inc.	$65	2019
AltaGas	WGL Holdings Inc.	$6,955	2018
Algonquin Power & Utilities	Empire District Electric Co	$2,349	2017
Fortis Inc.	ITC Holdings Corp	$11,577	2016
Emera Inc.	TECO Energy Inc.	$10,585	2016
Caisse de dépôt et placement	IPALCO Enterprises Inc.	$134	2016
Caisse de dépôt et placement	IPALCO Enterprises Inc.	$247	2015
Algonquin Power & Utilities	New Hampshire Gas Corp	$3	2015
Fortis Inc.	UNS Energy Corp	$4,383	2014
Algonquin Power & Utilities	New England Gas Company	$74	2013
Fortis Inc.	CH Energy Group Inc.	$1,526	2013
Algonquin Power & Utilities	Natural Gas Distribution Operations	$141	2013
Algonquin Power & Utilities	California Pacific Electric Co.	$39	2012
AltaGas	SEMCO Holding Corp	$1,156	2012
Algonquin Power & Utilities	Midwest Natural Gas Distribution	$124	2012
Algonquin Power & Utilities	Granite State / EnergyNorth	$285	2012
Gaz Metro LP	Central Vermont Public Service	$700	2012
Emera Inc	Maine & Maritimes Corporation	$99	2010
Gaz Métro LP	Green Mountain Power Corp	$293	2007
NS Power Holdings Inc.	Bangor Hydro-Electric Co.	$365	2001
Total U.S. Acquisitions by Canadian Utilities		**$44,705**	
U.S. Buyers Acquiring Canadian Utilities Since 2000			
Berkshire Hathaway Inc.	AltaLink LP	$5,683	2014
Investor Consortium	Terasen Water & Utility	$110	2006
Kinder Morgan Inc.	Terasen Inc.	$5,246	2005
Total Canadian Acquisitions by U.S. Utilities		**$11,039**	

As shown, the value of Canadian acquisitions in the U.S. totaled approximately $44.7 billion, while U.S. acquisitions in Canada were approximately $11 billion, for a ratio of approximately 4:1. In the last decade (i.e., 2011 – 2021), capital for utility investments has flowed overwhelmingly from Canada to the U.S. Specifically, Canadian investors have spent $43.9 billion in 19 different U.S. acquisitions, while U.S. investors spent just $5.7 billion in a single Canadian acquisition. One equity analyst recently characterized Canadian utilities as "U.S. utilities in disguise," noting that the U.S. operations of Canadian utilities now "are the largest driver of growth" and "represent the lion's share of the group's income."[252]

The fewer U.S. acquisitions in Canada can be explained, in part, by the smaller number of potential Canadian IOU targets. Canadian companies also see higher allowed shareholder returns and opportunities for growth in the U.S. as favorable. To further test that conclusion, Concentric studied a selection of recent cross-border transactions (both completed and attempted) in greater depth to understand the factor(s) underlying this cross-border flow of capital. These case studies are discussed in the bullets below:

- Fortis / ITC: On October 14, 2016, Fortis Inc. ("Fortis") paid approximately $11.6 billion to acquire ITC Holdings Corp. ("ITC"), a fully regulated electric transmission utility providing service in eight states in the Midwestern U.S. Fortis emphasized the attractiveness of FERC's allowed returns and formula rate structure when explaining the strategic rationale for the transaction to its investors. Specifically, Fortis identified the "[c]onstructive ROEs and greater equity in OpCo capital structures" and that the "[f]orward-looking rate-setting mechanism with true-up provides timely recovery and reduces regulatory lag."[253] On a call with investors to discuss the transaction, Barry Perry, Fortis' then President and Chief Executive Officer, stated that "FERC is a supportive regulator, the returns at FERC are greater than 11%, and the equity thickness is 60% on these assets. Let me just repeat that again, returns are greater than 11%, and the equity thickness is 60%."[254]
- Emera / TECO: Emera Inc. ("Emera") acquired TECO Energy Inc. ("TECO") on July 1, 2016, in a transaction valued at approximately $10.6 billion. TECO is a holding company that primarily owns electric and natural gas utilities in Florida and New Mexico. Emera characterized these regulatory jurisdictions as "constructive," noting that they have authorized ROEs of 10 percent or more and employ "[c]onstructive rate design with mechanisms in place to adjust rates on a timely basis."[255] Further, in a conference call with investors following the announcement of the transaction, TECO's regulatory climates were characterized as "very favorable" with "attractive allowed returns on equity."[256] In fact, one analyst from CIBC World Markets Inc. questioned whether the company's capital allocation

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[252] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 5.
[253] Fortis Inc, February 2016 Investor Presentation, p. 13.
[254] Thomson Reuters Streetevents, Transcript of February 9, 2016, Conference Call, "Fortis Inc to Acquire ITC Holdings Corp – M&A Call."
[255] Emera Inc., "Emera to Acquire TECO Energy: Building a North American Energy Leader," September 8, 2015, at 12.
[256] S&P Capital IQ, McGraw Hill Financial, Transcript of Emera Incorporated M&A Call, September 4, 2015, at 5-6.

decisions would be swayed by the relatively lower returns authorized in the Canadian jurisdictions in which the Company operates.[257]

- Hydro One / Avista: While ultimately not consummated, Hydro One Limited ("Hydro One") announced in July 2017 that it had reached a $5.3 billion agreement to acquire Avista Corporation ("Avista"), a regulated utility providing electric and natural gas service in Washington, Idaho, Oregon, Montana and Alaska. S&P explained that Hydro One was "lured" to Avista "in part by the company's higher authorized returns on equity, attractive allowed capital structures and geographically diverse, multistate service territory that promised a clear path toward rate base growth."[258] Hydro One specifically noted that "Avista's assets provide an opportunity to expand and diversify the footprint to new regulatory jurisdictions with higher ROEs and attractive allowed capital structures."[259]

Generally, while the transaction participants in the above case studies also noted other value drivers (e.g., growth prospects, diversification, proven management teams, etc.), these statements indicate that Canadian utilities (1) are investing capital in the U.S. at least in part because of the higher equity returns generally offered in those jurisdictions, and (2) perceive the regulatory environment in U.S. jurisdictions as supportive. In other words, our analysis shows that Canadian utilities are choosing to invest in U.S. where higher returns are available than in Canada. This is direct market evidence of better potential reward for taking on a similar level of risk.

5. Country Risk Comparisons

The previous three subsections discussed the environments in the U.S. and Canada from a utility perspective. From a macroeconomic perspective, country-specific economic, business and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit, rates Canada and the U.S. precisely the same from an overall country risk perspective (i.e., A) with AAA being the highest rating.[260] The Economist provides the following description of its country risk ratings:

> *The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk*

[257] *Id.*, at 17.
[258] S&P Global Market Intelligence, "After Busy Decade of M&A, Canada's Big Utilities Hone Focus on Regulated Growth," January 15, 2020.
[259] Hydro One, July 19, 2017, Investor Presentation, "Hydro One to Acquire Avista Creating a North American Utility Leader."
[260] The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, at 30.

trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.[261]

Figure 44 summarizes the country risk ratings for Canada and the U.S. as of August 2021.

Figure 44: Country Risk Ratings

	Canada	**U.S.**
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are highly comparable in a global context.

Additionally, the magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[262] Canada is currently the U.S.' 2nd largest goods trading partner overall with $525.7 billion in total (two way) goods trade during 2020.[263] This is an average two-way trade of $US 1.4 billion per day, which increased to $1.8 billion per day during the first six months of 2021. This is an indication of the high degree of integration between the two economies.

Schedule 5 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth

261 *Ibid*.
262 U.S. Department of State (https://www.state.gov/u-s-relations-with-canada).
263 https://www.census.gov/foreign-trade/balance/c1220.html.

and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries.

6. Country Risk Conclusions

Regulated utilities in both Canada and the U.S. participate in an integrated North American market for capital. While authorized equity ratios have historically diverged between the two countries, our analysis suggests that this divergence is no longer justified by differentials in risk. Rather, equity investors do not perceive any meaningful differential in risk between investments in Canadian utilities as compared to investments in U.S. utilities. This conclusion is corroborated by reports from Scotiabank, UBS, and recent utility trading multiples. However, the disparity in authorized costs of capital is causing Canadian utilities to seek investment opportunities in the U.S. to benefit from the higher authorized returns. In contrast, very few U.S. firms have acquired Canadian utilities. Debt investors perceive the regulatory environments in both the U.S. and Canada as credit supportive. Moody's perception of the supportiveness of the regulatory environment in the U.S. has improved markedly in recent years. In fact, Moody's observed that regulated utilities in the U.S. tend to exhibit stronger financial metrics than similarly rated peers in Canada. While S&P perceives the regulatory environment in Canadian jurisdictions as slightly more supportive than in the U.S. on average, S&P has also recently observed that the interests of stakeholders in Ontario have become "unbalanced" due in large part to low authorized costs of capital.

Further, the economies of Canada and the U.S. are highly integrated, and macroeconomic indicators for the two countries (e.g., GDP growth, bond yields, inflation rate, etc.) are quite correlated. The two countries are each other's largest export market. According to an independent, third-party evaluation from the Economist, the two countries have comparable risks from a global perspective.

For all these reasons, our view is that it is not necessary to adjust the equity ratio data from U.S. firms for purposes of establishing Enbridge Gas' equity ratio. Such an adjustment would be inconsistent with the market's view that the business and regulatory environments of the two countries are generally comparable. There are, of course, differences in risk between individual companies operating in the U.S. and/or Canada. As discussed previously, we have accounted for those differences by comparing the business and financial risks of Enbridge Gas to the business and financial risks of the proxy companies in a variety of ways. As a general matter, our position is that it is not appropriate to make adjustments to U.S. equity ratio data simply because that data relates to companies that operate in the U.S. Nonetheless, recognizing the OEB's prior concern, our recommended equity ratio of 42% for Enbridge Gas reflects a significant implicit downward adjustment of 10% from the U.S. peer group which averages 52.0%.

SECTION 5(d):
FAIR RETURN STANDARD CONCLUSIONS AND RECOMMENDATIONS

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

- Enbridge Gas is of average risk when compared to the proxy groups:
  - The Company bears Energy Transition risk that is comparable, or greater than the broader natural gas distribution industry and the proxy companies.
  - Enbridge Gas has several deferral and variance accounts for its operations, as do other proxy companies.
  - The credit metrics implied by the Company's regulated operations in 2021 are generally weaker than the proxy companies, although its FFO/Debt percentage and Debt/EBITDA metrics are better than those of the Canadian HoldCo group.
  - Enbridge Gas is significantly larger than the proxy companies on average. However, the regulatory and economic diversity of its operations are limited because it operates only in Ontario. Further, the OEB has made clear that it does not view size as a proxy for risk. Therefore, it is not necessary to adjust the proxy group equity ratio data to account for the Company's size.
  - The Company's weighted authorized equity return (i.e., authorized return on equity multiplied by deemed equity thickness) is among the lowest in North America, indicating greater financial risk.
- Due to the Energy Transition, investors now perceive investments in regulated gas utilities as riskier than investments in regulated electric utilities. Therefore, the Company's authorized equity ratio should be higher than the authorized equity ratio for Ontario's electric utilities. Ontario's electric distributors benefit from many of the same constructive ratemaking mechanisms available to Enbridge Gas (or that the Company is requesting in its upcoming rebasing application), such as multi-year rate plans and SFV rate design.
- ATCO Gas, Energir, and FortisBC Energy are the three natural gas distribution utilities in Canada with authorized common equity ratios that are closest to the Company's authorized equity ratio of 36%. These three utilities have an average authorized equity ratio of 39.25% after accounting for preferred equity.

- Investors historically have perceived investments in electric generation as riskier than investments in regulated natural gas distribution utilities (although that view is subject to re-examination in an energy transition environment). OPG's equity ratio of 45% likely sets a ceiling for the OEB on the appropriate authorized equity ratio for Enbridge Gas. We note, however, that OPG's access to capital benefits from provincial support.
- The Company must maintain financial strength to manage the Energy Transition while maintaining safe and reliable service to its customers.
- Investor-owned utilities in both Canada and the U.S. participate in an integrated, international market for capital. Investors no longer perceive significant differences in the supportiveness of utility regulation between the two countries, although differences still exist among individual jurisdictions.

On a relative risk basis, Concentric finds Enbridge Gas should fall towards the middle of the spectrum of risk profiles established by the proxy companies. Depending on the analytical approach employed, and proxy group studied, the proxy group's mean equity ratio ranges between 41.28% and 56.46%. As discussed earlier in the report, however, Concentric places less weight on the equity ratios at utility holding companies (versus those at regulated operating companies) because those companies reflect a different risk profile than the regulated operations of Enbridge Gas.

Enbridge Gas has the lowest deemed equity ratio of any investor-owned gas utility in North America despite its average risk profile. In addition, in recent years the OEB's adjustment formula has provided ROEs that are among the lowest of any investor-owned electric or gas utility in Canada or the U.S. The combination of the lowest deemed equity ratio and the low authorized ROEs in recent years places Enbridge Gas at a competitive disadvantage in terms of attracting capital and compensating existing shareholders.

An equity ratio of 36% is not sufficient to compensate investors for the risks associated with the ongoing Energy Transition, where anti-carbon sentiment is causing investors to view the entire industry with more skepticism due to concerns about whether long-term investments in gas plant will be fully recovered. The political and regulatory risk of the natural gas industry have increased as compared with 2012 and support the need for a higher deemed equity ratio for Enbridge Gas.

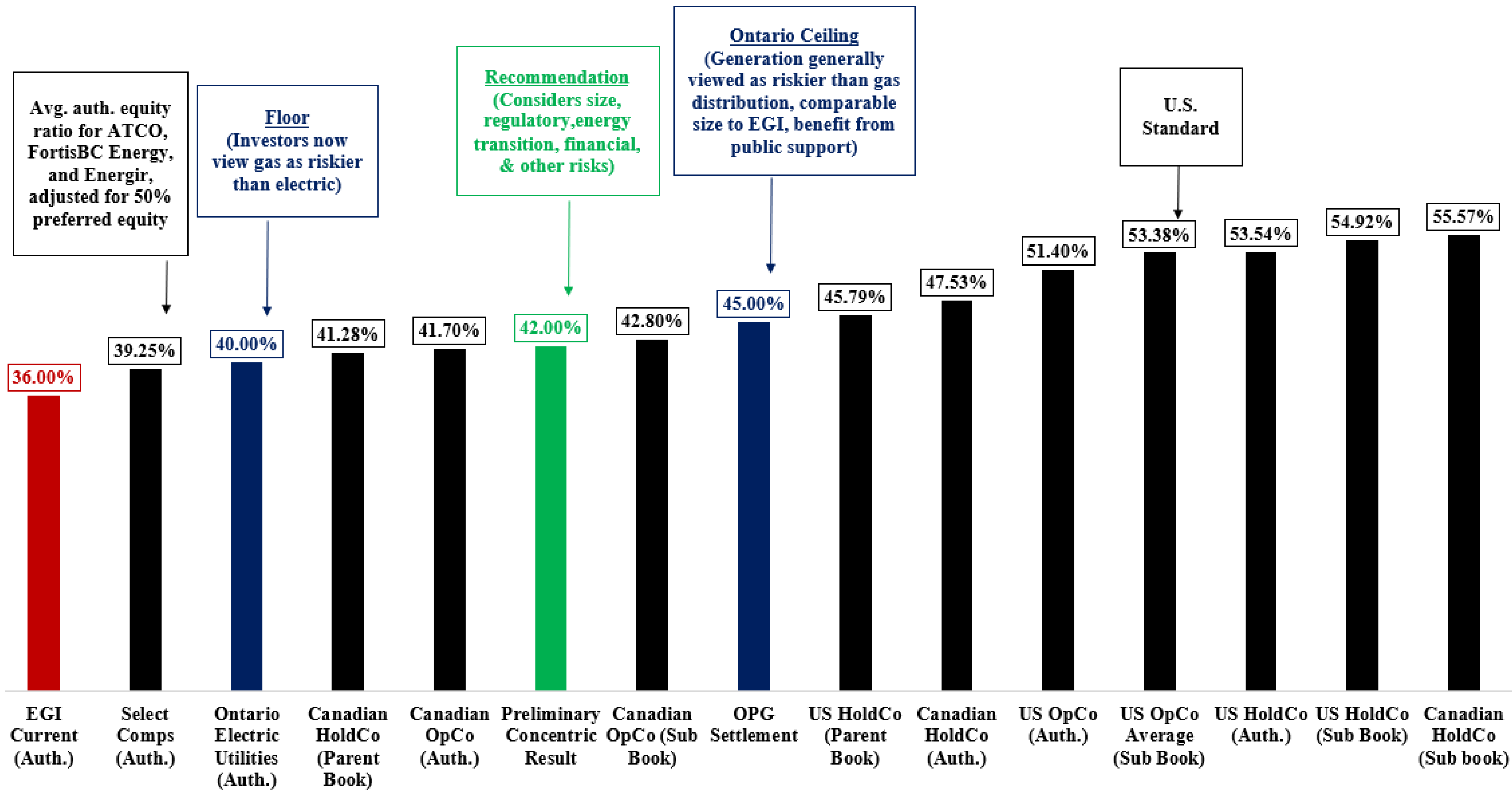
Given the risk factors noted above, we conservatively recommend that Enbridge Gas' authorized equity thickness fall within the range of 40% to 45%. We specifically recommend a deemed equity thickness of 42% for the Company for the upcoming rate setting period.[264] The points below, and the accompanying Figure 45, summarize certain factors that inform this recommendation:

- Enbridge Gas' risk profile has materially increased since 2012, warranting a revisitation of its deemed equity ratio.
- The Company's current deemed equity thickness does not satisfy the comparable investment standard component of the Fair Return Standard.
- The lower end of this recommended range is consistent with (1) the currently deemed equity thickness of 40% for Ontario's electric distributors, which we view as less risky as a group than the Company, and (2) the average authorized equity ratio for ATCO Gas, FortisBC Energy, and Energir, after accounting for preferred equity.
- The upper end of this recommended range is consistent with OPG's deemed equity thickness, which we currently view as setting an upper bound for the Company in the context of previous OEB decisions.
- The specific deemed equity thickness recommendation of 42% falls between the two mean results produced for the Canadian OpCo proxy group.

The above recommendations assume that the Company's substantive proposals in this case (e.g., the continuation of its current deferral and variance accounts, SFV rate design, etc.) are approved as the Company proposed them. To the extent any of these proposals are not approved or are modified to provide less risk mitigation for the Company, a higher equity ratio may be warranted.

[264] Our understanding is that the Company, in order to mitigate customer bill impacts, is proposing to phase in the increase in its deemed equity ratio over the five-year term of the rate period, beginning at 38% in 2024, and increasing by 1% each year until reaching 42% in 2028.

Figure 45: Key Data Points in Equity Thickness Recommendation



APPENDIX A: RESUME OF JAMES M. COYNE

JAMES M. COYNE
Senior Vice President

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

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

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

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

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

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

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

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

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

“Energy Sector in Transition”, Ontario Energy Association, Toronto, ON, September 24, 2018.

“Understanding Regulated Utilities in Today’s Capital Markets”, NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

“Rate of Return: Where the Regulatory Rubber Meets the Road,” CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

“Innovations in Utility Business Models and Regulation”, The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

“M&A and Valuations,” Panelist at Infocast Utility Scale Solar Summit, September 2010

“The Use of Expert Evidence,” The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

“A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.”, The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

“Nuclear Power on the Verge of a New Era,” moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

“The Investment Implications of the Repeal of PUCHA,” Skadden Arps Client Conference, New York, NY, October 2005

“Anatomy of the Deal,” First Annual Energy Transactions Conference, Newport, RI, May 2005

“The Outlook for Wind Power,” Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

“Direction of U.S. M&A Activity for Utilities,” Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

“Outlook for U.S. Merger & Acquisition Activity,” Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

“Investor Perspectives on Emerging Energy Companies,” Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

“Electric Generation Asset Transactions: A Practical Guide,” workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

“New Strategic Options for the Power Sector,” Electric Utility Business Environment Conference, Denver, CO, May 1999

“Electric and Gas Industries: Moving Forward Together,” New England Gas Association Annual Meeting, November 1998

“Opportunities and Challenges in the Electric Marketplace,” Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00XXX	Cost of Capital (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Cost of Capital (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company		Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

APPENDIX B: RESUME OF DANIEL S. DANE

DANIEL S. DANE, CPA
Senior Vice President

Daniel S. Dane has more than 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has testified and provided expert reports on regulated ratemaking and utility performance matters for investor- and provincially-owned utilities, including on the cost of capital and capital structure, merger impacts, earnings sharing mechanisms and rate adjustment mechanisms, revenue requirements, lead-lag studies/cash working capital, and utility productivity and benchmarking. That testimony includes assessments of Ontario Power Generation's equity thickness before the OEB in EB-2016-0152 and EB-2020-0290. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the OEB. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
CE Capital Advisors, Inc.
Senior Vice President (Concentric/CE Capital)
Financial and Operations Principal (CE Capital)

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

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

Colgate University
B.A., Economics, 1996

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state administrative rate setting and merger approval proceedings regarding merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development.

Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; regulatory lag; and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation and natural gas pipeline facilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services provided to U.S. and Canadian investor-owned utilities.

Valuation Services

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

Litigation Advisory Assignments

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

Management and Operations Consulting Assignments

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

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

American Institute of Certified Public Accountants, 2011

CERTIFICATIONS

Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).

"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.

"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
The United Illuminating Company	09/22	The United Illuminating Company	Docket No. 22-08-08	Revenue Requirements
SJW Group and Connecticut Water Service, Inc.	4/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study Cash Working Capital
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-lag Study Cash Working Capital
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Massachusetts Department of Public Utilities				
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Revenue Requirement Lead-lag Study Cash Working Capital
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017; Administrative and General Expense Allocations
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Revenue Requirement Lead-lag Study Cash Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study Cash Working Capital
Oklahoma Corporate Commission				
Liberty Utilities Co.	02/22	Liberty-Empire	Cause No. PUD 202100163	Return on Equity Capital Structure
Liberty Utilities Co.	06/22	Liberty-Empire	Cause No. PUD 202100050	Winter Storm Funding and Cost Recovery
Public Utility Commission of Texas				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
Regulatory Commission of Alaska				
Golden Heart Utilities, Inc. and College Utilities Corporation	08/21	Golden Heart Utilities, Inc. and College Utilities Corporation	U-21-070 U-21-071	Lead-lag Study Cash Working Capital
Rhode Island Division of Public Utilities and Carriers				
PPL Corp.	11/21	Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals	Docket No. 21-09	Merger Impacts Public Interest

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
South Dakota Public Service Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., and any other necessary affiliates entities to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer
Nova Scotia Utility and Review Board				
Nova Scotia Power, Inc.	01/22	Nova Scotia Power, Inc.	M10431	Earnings Sharing Mechanism and Regulatory Adjustment Mechanisms
Ontario Energy Board				
Hydro One Networks Inc.	08/21	Hydro One Networks Inc.	EB 2021-0110	Productivity Framework Review
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Cost of Capital: Equity Thickness
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Cost of Capital: Equity Thickness

SCHEDULE 1 - SUMMARY OF CREDIT METRICS ANALYSIS

Company / Proxy Group	Debt to Capital Ratio	EBIT / Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Enbridge Gas Inc. (S&P)	49.7%	4.29	4.33	12.4%	6.21
Enbridge Gas Inc. (Reg-only)	64.0%	2.350	3.92	12.19%	5.94
Canadian OpCo Average [1]	N/A	N/A	N/A	N/A	N/A
Canadian HoldCo Average	58.0%	4.08	4.20	11.5%	6.53
US OpCo Average	49.7%	8.34	10.18	19.3%	4.56
US HoldCo Average	57.8%	6.94	5.51	14.2%	5.75

Notes:

[1] Insufficient companies in this proxy group are rated by S&P to produce meaningful results.

SCHEDULE 1- CREDIT METRICS ANALYSIS

Company Name	Ticker	Debt to Capital Ratio	EBIT / Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Enbridge Gas Inc. (Per S&P)		49.7%	4.29	4.33	12.42%	6.21
Enbridge Gas Inc. (Regulated-Only)		64.0%	2.35	3.92	12.19%	5.94
Canadian HoldCo Group						
Algonquin Power and Utilities Corp.	AQN	49.7%	4.29	4.33	12.42%	6.21
AltaGas Utilities Inc	ALA	56.8%	4.55	4.55	12.07%	6.17
Canadan Utilities Ltd.	CU	62.0%	3.50	3.67	11.30%	6.25
Emera Inc.	EMA	61.5%	3.52	3.78	9.89%	7.35
Fortis, Inc.	FTS	58.2%	3.74	3.95	10.91%	6.87
Hydro One Inc.	H	59.6%	4.90	4.92	12.48%	6.34
Canadian HoldCo Average		**58.0%**	**4.08**	**4.20**	**11.51%**	**6.53**
US OpCo Group						
Southern California Gas Company		57.0%	7.01	9.73	20.50%	3.85
Consumers Energy Company		50.3%	6.33	6.44	21.71%	3.91
Northern Illinois Gas Company		N/A	N/A	N/A	N/A	N/A
DTE Gas Company		51.4%	5.90	6.72	19.12%	4.45
Consolidated Edison Company of NY		54.9%	5.30	5.37	17.54%	4.63
The Eash Ohio Gas company		44.7%	22.76	29.15	20.61%	4.51
Brooklyn Union Gas Company [1]		37.5%	3.86	4.73	14.63%	6.46
Atlanta Gas Light Company		N/A	N/A	N/A	N/A	N/A
Columbia Gas of Ohio, Inc.		N/A	N/A	N/A	N/A	N/A
The Peoples Gas Light and Coke Company		52.4%	7.21	9.09	20.91%	4.11
US OpCo Average		**49.7%**	**8.34**	**10.18**	**19.29%**	**4.56**
US HoldCo Group						
Atmos Energy Corporation [2]	ATO	49.0%	14.15	5.96	15.62%	5.30
New Jersey Resources Corporation	NJR	N/A	N/A	N/A	N/A	N/A
NiSource Inc.	NI	62.2%	4.70	5.15	13.59%	5.91
Northwest Natural Gas Company	NWN	58.5%	5.85	5.38	15.32%	4.82
ONE Gas, Inc.	OGS	63.2%	8.19	4.96	10.80%	7.54
South Jersey Industries, Inc.	SJI	57.8%	4.84	4.69	13.55%	5.81
Southwest Gas Corporation	SWX	55.3%	5.87	6.19	15.20%	5.39
Spire, Inc. [2]	SR	58.7%	4.99	6.23	15.34%	5.46
US HoldCo Average		**57.8%**	**6.94**	**5.51**	**14.20%**	**5.75**

Notes & Sources:

All values are based on S&P Capital IQ, Credit Stats Direct, Select Stats & Ratios as calculated and adjusted by S&P Capital IQ for the most recent period, December 31, 2021 unless otherwise stated.

[1] Fiscal year ended on March 31, 2022

[2] Fiscal year ended on September 30, 2021

SCHEDULE 2- Sumary of Energy Transition Risk Comparison

Proxy Group	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	% Depreciated 2020	% Depreciated 2021
Canadian OpCo	22.21	18.69	31.48	27.96	29.88%	33.24%
Canadian HoldCo	22.64	21.45	34.05	32.16	33.44%	33.25%
US OpCo	28.07	28.27	38.88	38.72	28.90%	28.03%
US HoldCo	28.61	26.64	38.98	38.01	26.71%	28.96%
Enbridge Gas	**27.51**	**27.79**	**35.40**	**35.88**	**22.29%**	**22.56%**

SCHEDULE 2- Analysis
Proxy Group One: Canadian Operating Companies

Company	Ticker	Gross Plant ($M) 2020	Gross Plant ($M) 2021	Accum. Depr. ($M) 2020	Accum. Depr. ($M) 2021	Depr. Expense ($M) 2020	Depr. Expense ($M) 2021	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	Percent Depreciated 2020	Percent Depreciated 2021	Notes
Engridge Gas Inc.		$20,640	$21,744	$4,600	$4,905	$583	$606	27.5	27.8	35.4	35.9	22.29%	22.56%	[1]

Proxy Group One: Canadian Operating Companies

Company	Ticker	Gross Plant ($000) 2020	Gross Plant ($000) 2021	Accum. Depr. ($000) 2020	Accum. Depr. ($000) 2021	Depr. Expense ($000) 2020	Depr. Expense ($000) 2021	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	Percent Depreciated 2020	Percent Depreciated 2021	Notes
AltaGas Utilities Inc.	N/A	$678,583	$724,640	$215,544	$229,669	$20,121	$24,171	23.0	20.5	33.7	30.0	31.76%	31.69%	[2]
ATCO Gas	N/A	$5,434,406	$5,470,814	$2,041,785	$2,088,017	$199,937	$206,899	17.0	16.3	27.2	26.4	37.57%	38.17%	[3]
Energir	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
FortisBC Energy	N/A	$7,413,000	$7,823,000	$2,206,000	$2,335,000	$241,000	$285,000	21.6	19.3	30.8	27.4	29.76%	29.85%	[4]
Gazifere 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	N/A	
Heritage Gas Limited	N/A	$280,861	N/A	$57,376	N/A	$8,197	N/A	27.3	N/A	34.3	N/A	20.43%	N/A	[5]
Liberty Gas New Brunswick	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd (Fort St. John/Dawson Cre	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd (Tumbler Ridge)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Average								**22.2**	**18.7**	**31.5**	**28.0**	**29.88%**	**33.24%**	

Proxy Group Two: Canadian Holding Companies

Company	Ticker	Gross Plant ($M) 2020	Gross Plant ($M) 2021	Accum. Depr. ($M) 2020	Accum. Depr. ($M) 2021	Depr. Expense 2020	Depr. Expense 2021	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	Percent Depreciated 2020	Percent Depreciated 2021	
Algonquin Power & Utilities												N/A	N/A	
Liberty Utilities (New England Natural Gas Compa	AQN	$300	$381	$98	$105	$10	$10	21.0	26.5	31.3	36.6	32.76%	27.52%	[4]
Empire District Gas Company	AQN	$110	$116	$42	$46	$5	$5	14.8	14.3	24.0	23.8	38.27%	39.99%	[4]
Liberty Utilities (Midstates Natural Gas) Corp	AQN	$302	$318	$101	$109	$12	$12	16.2	17.0	24.4	25.8	33.32%	34.21%	[4]
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	$720	N/A	$213	N/A	$23	N/A	21.9	N/A	31.1	N/A	29.64%	N/A	[4]
Liberty Gas New Brunswick	AQN	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Average	AQN	$1,432	$815	$454	$260	$50	$28	19.7	20.1	28.8	29.5	31.74%	31.91%	
AltaGas Inc.														
ENSTAR Natural Gas Company	ALA							N/A	N/A	N/A	N/A	N/A	N/A	
SEMCO Energy, Inc.	ALA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Washington Gas Light Company	ALA	$6,097	N/A	$1,738	N/A	$147	N/A	29.6	N/A	41.4	N/A	28.50%	N/A	[4]
Average	ALA	$6,097	$0	$1,738	$0	$147	$0	29.6	N/A	41.4	N/A	28.50%	N/A	
Canadian Utilities Ltd.														
ATCO Gas	CU	$5,434	$5,471	$2,042	$2,088	$200	$207	17.0	16.3	27.2	26.4	37.57%	38.17%	[3]
Average	CU	$5,434	$5,471	$2,042	$2,088	$200	$207	17.0	16.3	27.2	26.4	37.57%	38.17%	
Emera Inc.														
Peoples Gas System	EMA	$2,177	$2,466	$807	$846	$48	$56	28.3	29.1	45.0	44.3	37.07%	34.32%	[4]
New Mexico Gas Company, Inc.	EMA	$1,294	N/A	$608	N/A	$36	N/A	19.2	N/A	36.3	N/A	47.02%	N/A	[4]
Average	EMA	$3,471	$2,466	$1,416	$846	$84	$56	24.5	29.1	41.3	44.3	40.78%	34.32%	
Fortis Inc.														
UNS Gas, Inc.	FTS	$406	$414	$88	$87	$12	$13	25.6	25.5	32.8	32.3	21.76%	21.04%	[6]
Central Hudson Gas & Electric Corporation	FTS	$678	$734	$138	$145	$16	$18	33.5	33.5	42.0	41.7	20.37%	19.73%	[4]
FortisBC Energy	FTS	$7,413	$7,823	$2,206	$2,335	$241	$285	21.6	19.3	30.8	27.4	29.76%	29.85%	
Average	FTS	$8,496	$8,971	$2,432	$2,567	$269	$315	22.5	20.3	31.5	28.4	28.63%	28.61%	
Hydro One, Ltd.														
N/A	H	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Average	H	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A	N/A	N/A	
Average								**22.6**	**21.5**	**34.1**	**32.2**	**33.44%**	**33.25%**	

Proxy Group Three: US Operating Companies

Company	Ticker	Gross Plant ($M) 2020	Gross Plant ($M) 2021	Accum. Depr. ($M) 2020	Accum. Depr. ($M) 2021	Depr. Expense ($M) 2020	Depr. Expense ($M) 2021	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	Percent Depreciated 2020	Percent Depreciated 2021	
Southern California Gas Company	N/A	$21,180	$23,104	$6,437	$6,861	$649	$711	22.7	22.8	32.6	32.5	30.39%	29.70%	[7]
Consumers Energy Company	N/A	$9,061	$10,073	$3,120	$3,314	$282	$304	21.1	22.3	32.1	33.2	34.44%	32.90%	[4]
Northern Illinois Gas Company	N/A	$8,539	$9,226	$3,763	$3,892	$251	$272	19.1	19.6	34.1	33.9	44.06%	42.18%	[4]
DTE Gas Company	N/A	$6,162	$6,638	$2,150	$2,202	$146	$166	27.6	26.8	42.3	40.0	34.89%	33.17%	[4]
Consolidated Edison Company of New York, Inc.	N/A	$9,629	$11,061	$1,724	$1,901	$295	$327	26.8	28.0	32.6	33.8	17.90%	17.18%	[4]
The East Ohio Gas Company	N/A	$5,075	$5,503	$1,303	$1,371	$119	$134	31.7	30.8	42.7	41.0	25.68%	24.91%	[4]
Brooklyn Union Gas Company	N/A	$7,294	$7,824	$1,181	$1,277	$134	$139	45.8	47.2	54.6	56.4	16.19%	16.32%	[4]
Atlanta Gas Light Company	N/A	$6,085	$6,513	$1,887	$1,978	$144	$153	29.2	29.6	42.3	42.5	31.02%	30.36%	[4]
Columbia Gas of Ohio, Inc.	N/A	$4,962	$5,389	$1,211	$1,301	$121	$131	30.9	31.1	40.9	41.1	24.41%	24.14%	[4]
The Peoples Gas Light and Coke Company	N/A	$6,155	$6,470	$1,539	$1,636	$178	$198	25.9	24.4	34.5	32.7	25.00%	25.29%	[4]
Average		**$84,143**	**$91,802**	**$24,315**	**$25,732**	**$2,318**	**$2,535**	**28.1**	**28.3**	**38.9**	**38.7**	**28.90%**	**28.03%**	

Proxy Group Four: US Holding Companies

Company	Ticker	Gross Plant ($M) 2020	Gross Plant ($M) 2021	Accum. Depr. ($M) 2020	Accum. Depr. ($M) 2021	Depr. Expense ($M) 2020	Depr. Expense ($M) 2021	Remaining Life 2020	Remaining Life 2021	Total Life 2020	Total Life 2021	Percent Depreciated 2020	Percent Depreciated 2021	
Atmos Energy Corporation														
Atmos Energy Corporation	ATO	$16,665	N/A	$3,735	N/A	$446	N/A	29.0	N/A	37.3	N/A	22.41%	N/A	[4]
Weighted Average	ATO	$16,665	$0	$3,735	$0	$446	$0	29.0	N/A	37.3	N/A	22.41%	N/A	
New Jersey Resources Corporation														
New Jersey Natural Gas Company	NJR	$2,721	N/A	$530	N/A	$74	N/A	29.5	N/A	36.7	N/A	19.48%	N/A	[4]
Weighted Average	NJR	$2,721	$0	$530	$0	$74	$0	29.5	N/A	36.7	N/A	19.48%	N/A	
NiSource Inc.														
Northern Indiana Public Service Company	NI	$3,188	N/A	$1,365	N/A	$74	N/A	24.7	N/A	43.3	N/A	42.82%	N/A	[4]
Columbia Gas of Kentucky, Incorporated	NI	$593	N/A	$162	N/A	$15	N/A	28.5	N/A	39.1	N/A	27.26%	N/A	[4]
Columbia Gas of Maryland, Incorporated	NI	$251	N/A	$61	N/A	$7	N/A	28.8	N/A	38.1	N/A	24.44%	N/A	[4]
Columbia Gas of Ohio, Inc.	NI	$4,962	$5,389	$1,211	$1,301	$121	$131	30.9	31.1	40.9	41.1	24.41%	24.14%	[4]
Columbia Gas of Pennsylvania, Inc.	NI	$2,851	$3,141	$505	$553	$79.16	$87.56	29.6	29.6	36.0	35.9	17.70%	17.60%	[8]
Columbia Gas of Virginia, Incorporated	NI	$1,497	N/A	$394	N/A	$37	N/A	29.9	N/A	40.6	N/A	26.34%	N/A	[4]
Weighted Average	NI	$13,342	$8,530	$3,698	$1,854	$333	$219	29.0	30.5	40.1	39.0	27.72%	21.74%	
Northwest Natural Holding Company														
Northwest Natural Gas Company	NWN	$3,675	$3,855	$1,542	$1,613	$105	$114	20.4	19.7	35.1	33.9	41.96%	41.84%	[4]
Average	NWN	$3,675	$3,855	$1,542	$1,613	$105	$114	20.4	19.7	35.1	33.9	41.96%	41.84%	
ONE Gas, Inc.														
Kansas Gas Service Company, Inc.	OGS	$2,174	N/A	$697	N/A	$68	N/A	21.7	N/A	31.9	N/A	32.05%	N/A	[9]
Oklahoma Natural Gas Company	OGS	$2,786	N/A	$870	N/A	$76	N/A	25.0	N/A	36.4	N/A	31.23%	N/A	[10]
Texas Gas Service Company, Inc.	OGS	$1,505	N/A	$309	N/A	$42	N/A	28.5	N/A	35.8	N/A	20.53%	N/A	[4]
Average	OGS	$6,465	$0	$1,876	$0	$187	$0	24.6	N/A	34.6	N/A	29.02%	N/A	
South Jersey Industries, Inc.														
South Jersey Gas Company	SJI	$3,388	N/A	$607		$65	N/A	42.8	N/A	52.1	N/A	17.91%	N/A	[11]
Average	SJI	$3,388	$0	$607	$0	$65	$0	42.8	N/A	52.1	N/A	17.91%	N/A	
Southwest Gas Corporation														
Southwest Gas Corporation	SWX	$2,634	$2,832	$650	$694	$64	$70	30.9	30.5	41.0	40.5	24.66%	24.51%	[12]
Average	SWX	$2,634	$2,832	$650	$694	$64	$70	30.9	30.5	41.0	40.5	24.66%	24.51%	
Spire, Inc.														
Spire Gulf Inc.	SR	$357	$382	$120	$120	$11	$12	21.0	22.1	31.7	32.3	33.67%	31.49%	[13]
Spire Missouri Inc.	SR	$2,457	$2,643	$595	$628	$81	$71	23.0	28.3	30.3	37.1	24.22%	23.76%	[4]
Spire Alabama Inc.	SR	$2,477	$2,591	$1,117	$1,125	$59	$62	22.9	23.6	41.8	41.7	45.10%	43.41%	[4]
Average	SR	$5,291	$5,617	$1,832	$1,873	$152	$145	22.8	25.8	34.9	38.7	34.63%	33.35%	
Average		**$54,180**	**$20,834**	**$14,470**	**$6,035**	**$1,425**	**$548**	**28.6**	**26.6**	**39.0**	**38.0**	**26.71%**	**28.96%**	

Notes:
[1] Enbridge Gas Inc, Consolidated Financial Statements, December 31, 2020, at 19 and December 31, 2021 at 22
[2] AltaGas Canada distribution Finance and Operations Reports to the Alberta Utilities Commission, 2020 and 2021 Schedule 1, 2.1
[3] ATCO Gas Finance and Operations Reports to the Alberta Utilities Commission, 2016-2021, Schedule 1, 2.1
[4] S&P Capital IQ Pro
[5] Heritage Gas, NSUARB-NG-HG-R008 Compliance Filing, at 9 & 15
[6] UNS Gas Annual Reports to the Arizona Corporation Commission, Financial Statements, at 1, 3
[7] Southern California Gas Company 2021 Balance Sheets
[8] Columbia Gas of Pennsylvania Annual LDC Report 2021, at page 12
[9] 2019 & 2020 Source: Kansas Gas Service 2020 FERC Form 2, at 110 and 114
[10] 2019 & 2020 Source: Oklahoma Natural Gas Company 2020 FERC Form 2, at 112 and 114
[11] 2020 Source: South Jersey Gas 2020 FERC Form 2, at 114, 209
[12] Southwest Gas 2020 and 2021 FERC Form 2, at 110, 114, 209
[13] 2020 & 2021 Source: Spire Gulf Inc. 2020 FERC Form 2, at 110 and 114

SCHEDULE 3 - Summary of Regulatory Mechanism for Proxy Group

	Percentage of Companies Operating in Juridictions With …				
Proxy Group	**Formula-Based Ratemaking or Multi-Year Rate Plans**	**Fully or Partially Forecast Test Years**	**Full or Partial Decoupling**	**Capital Cost Trackers**	**Conservation Programs**
Canadian OpCo	44%	78%	67%	83%	50%
Canadian HoldCo	56%	61%	61%	67%	39%
US OpCo	40%	80%	100%	80%	80%
US HoldCo	42%	42%	88%	73%	50%
Enbridge Gas	Yes	Fully	Partial	Yes	Yes

Canadian OpCo - data not available for all companies

SCHEDULE 3 - COMPARISON OF ENBRIDGE GAS INC AND PROXY GROUP COMPANIES
RISK ASSESSMENT

Company	Operating Subsidiary	Jurisdiction	[1] Regulatory Framework	[2] Test Year	[3] Decoupling?	[4] Conservation Program Expenses	[5] Capital Cost Tracker
Canadian OpCo Proxy Group							
Apex Utilities Inc.	N/A	Alberta	Multi-year rate plans	Historical	No		Yes
ATCO Gas	N/A	Alberta	Multi-year rate plans	Historical	Partial		Yes
Energir	N/A	Quebec	Multi-year rate plans	Fully Forecast	Full	Yes	
FortisBC Energy	N/A	British Columbia	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
Gazifere Inc.	N/A	Quebec					
Heritage Gas Limited	N/A	Nova Scotia	Cost of service	Fully forecast	Full		Yes
Liberty Gas New Brunswick	N/A	New Brunswick	Cost of service	Fully Forecast	No		Yes
Pacific Northern Gas Ltd	N/A	British Columbia	Cost of service	Fully Forecast			
Pacific Northern Gas Ltd (FSJ/DC)	N/A	British Columbia	Cost of service	Fully Forecast			
Pacific Northern Gas Ltd (TR)	N/A	British Columbia	Cost of service	Fully Forecast			
			Multi-Year Rate Plans: 4 (44.4%)	Fully Forecast: 6 (66.7%)	Full: 3 (50.0%)	Yes: 3 (30.0%)	Yes: 5 (50.0%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 0 (0.0%)	Partial: 1 (16.7%)		
			Cost of service: 5 (55.6%)	Historical: 2 (22.2%)	No: 2 (33.3%)		
			Fair Value: 0 (0.0%)				
Canadian HoldCo Proxy Group							
Algonquin Power & Utilities Corp.	Liberty Utilities (Peach State Nat. Gas) Corp.	Georgia	Multi-Year rate plans	Partially Forecast	Full		
	Liberty Utilities (Midstates Natural Gas) Corp.	Illinois	Cost of service	Fully Forecast	Partial	Yes	
	Liberty Utilities (NE Nat Gas)	Massachusetts	Multi-Year rate plans	Historical	Full	Yes	Yes
	Empire District Gas Co.	Missouri	Original Cost/Fair Value	Partially Forecast	No		
	Liberty Utilities (Midstates)	Missouri	Original Cost/Fair Value	Partially Forecast	Partial		Yes
	Liberty Utilities EnergyNorth	New Hampshire	Multi-year rate plans	Historical	Full		Yes
	Liberty Gas New Brunswick	New Brunswick	Cost of service	Fully Forecast	No		Yes
AltaGas Ltd.	Enstar Natural Gas Co.	Alaska	Cost of service	Historical	No		
	SEMCO Energy Inc.	Michigan	Cost of service	Partially Forecast	No	Yes	Yes
	Washington Gas Light Co.	District of Columbia	Multi-year rate plans	Historical	No	Yes	Yes
	Washington Gas Light Co.	Maryland	Multi-year rate plans	Partially Forecast	Partial		Yes
	Washington Gas Light Co.	Virginia	Cost of service	Historical	Partial		Yes
Canadian Utilities Limited	ATCO Gas	Alberta	Multi-year rate plans	Historical	Partial		Yes
Emera Inc.	New Mexico Gas Co.	New Mexico	Multi-year rate plans	Fully Forecast	No	Yes	
	Peoples Gas System	Florida	Multi-year rate plans	Fully Forecast	No	Yes	Yes
Fortis Inc.	Central Hudson Gas & Electric	New York	Multi-year rate plans	Fully Forecast	Full		Yes
	UNS Gas Inc.	Arizona	Fair Value	Historical	Partial		
	FortisBC Energy	British Columbia	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
			Multi-Year Rate Plans: 10 (55.6%)	Fully Forecast: 6 (33.3%)	Full: 5 (27.8%)	Yes: 7 (38.9%)	Yes: 12 (66.7%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 5 (27.8%)	Partial: 6 (33.3%)		
			Cost of service: 5 (27.8%)	Historical: 7 (38.9%)	No: 7 (38.9%)		
			Fair Value: 3 (16.7%)				
US OpCo Proxy Group							
Southern California Gas Company	N/A	California	Multi-year rate plans	Fully Forecast	Full		
Consumers Energy Company	N/A	Michigan	Cost of service	Partially Forecast	Partial	Yes	
Northern Illinois Gas Company	N/A	Illinois	Cost of service	Fully Forecast	Partial	Yes	Yes
DTE Gas Company	N/A	Michigan	Cost of service	Partially Forecast	Partial	Yes	Yes
Consolidated Edison Company of NY	N/A	New York	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
East Ohio Gas	N/A	Ohio	Cost of service	Historical	Full	Yes	Yes
Brooklyn Union Gas Company	N/A	New York	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
Atlanta Gas Light	N/A	Georgia	Multi-year rate plans	Partially Forecast	Full		Yes
Columbia Gas of Ohio	N/A	Ohio	Cost of service	Historical	Full	Yes	Yes
Peoples Gas Light and Coke	N/A	Illinois	Cost of service	Fully Forecast	Partial	Yes	Yes
			Multi-Year Rate Plans: 4 (40.0%)	Fully Forecast: 5 (50.0%)	Full: 6 (60.0%)	Yes: 8 (80.0%)	Yes: 9 (90.0%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 3 (30.0%)	Partial: 4 (40.0%)		
			Cost of service: 6 (60.0%)	Historical: 2 (20.0%)	No: 0 (0.0%)		
			Fair Value: 0 (0.0%)				

			[1]	[2]	[3]	[4]	[5]
Company	**Operating Subsidiary**	**Jurisdiction**	**Regulatory Framework**	**Test Year**	**Decoupling?**	**Conservation Program Expenses**	**Capital Cost Tracker**
US HoldCo Proxy Group							
Atmos Energy Corporation	Atmos Energy Corporation	Kansas	Cost of service	Historical	Partial		Yes
	Atmos Energy Corporation	Kentucky	Cost of service	Fully Forecast	Partial	Yes	Yes
	Atmos Energy Corporation	Louisiana	Multi-year rate plans	Historical	Partial		Yes
	Atmos Energy Corporation	Mississippi	Formula-based ratemaking	Partially Forecast	Partial	Yes	Yes
	Atmos Energy Corporation	Tennessee	Formula-based ratemaking	Fully Forecast	Partial		
	Atmos Energy Corporation	Texas	Formula-based ratemaking	Historical	Partial		Yes
New Jersey Resources Corporation	New Jersey Natural Gas Co.	New Jersey	Cost of service	Historical	Full	Yes	Yes
NiSource Inc.	Columbia Gas of Kentucky Inc	Kentucky	Cost of service	Fully Forecast	Partial	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Multi-year rate plans	Partially Forecast	Partial	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Multi-year rate plans	Partially Forecast	No	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Formula-based ratemaking	Fully Forecast	Partial		Yes
	Columbia Gas of Virginia Inc.	Virginia	Cost of service	Historical	Partial	Yes	Yes
Northwest Natural Gas Company	Northwest Natural Gas Co.	Oregon	Cost of service	Fully Forecast	Partial	Yes	
	Northwest Natural Gas Co.	Washington	Cost of service	Historical	No	Yes	
ONE Gas, Inc.	Kansas Gas Service Co.	Kansas	Cost of service	Historical	Partial		Yes
	Oklahoma Natural Gas Co.	Oklahoma	Cost of service	Historical	Partial	Yes	
	Texas Gas Service Co. Inc.	Texas	Formula-based ratemaking	Historical	Partial		Yes
South Jersey Industries, Inc.	Elizabethtown Gas Co.	New Jersey	Cost of service	Historical	Partial	Yes	Yes
	South Jersey Gas Co.	New Jersey	Cost of service	Historical	Full	Yes	Yes
Southwest Gas Corporation	Southwest Gas Corp.	Arizona	Fair Value	Historical	Full	Yes	Yes
	Southwest Gas Corp.	California	Multi-year rate plans	Fully Forecast	Full		
	Southwest Gas Corp.	Nevada	Cost of service	Historical	Full		Yes
Spire, Inc.	Spire Alabama Inc.	Alabama	Formula-based ratemaking	Fully Forecast	Partial		
	Spire Gulf Inc.	Alabama	Formula-based ratemaking	Fully Forecast	Partial		
	Spire Missouri Inc. - East	Missouri	Original Cost/Fair Value	Historical	Partial		Yes
	Spire Missouri Inc. - West	Missouri	Original Cost/Fair Value	Historical	No		Yes
			Multi-Year Rate Plans: 4 (15.4%)	Fully Forecast: 8 (30.8%)	Full: 5 (19.2%)	Yes: 13 (50.0%)	Yes: 19 (73.1%)
			Formula-based ratemaking: 7 (26.9%)	Partially Forecast: 3 (11.5%)	Partial: 18 (69.2%)		
			Cost of service: 12 (46.2%)	Historical: 15 (57.7%)	No: 3 (11.5%)		
			Fair Value: 3 (11.5%)				

Notes

[1] S&P Global Market Intelligence, "RRA Regulatory Focus: Alternative Ratemaking Plans in the US," April 16, 2020, at 2; Regulatory Research Associates commission profiles

[2] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 9/24/21

[3] - [5] Regulatory Research Associates, "Adjustment Clauses: A State-by-State Overview," July 18, 2022

SCHEDULE 4 - Summary Results of Equity Ratio Analysis

Analytical Results: All Proxy Groups (Mean)

Proxy Group	Gas Subsidiaries: Currently Authorized Equity Ratio	Gas Subsidiaries: 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	41.70%	42.80%	N/A
Canadian Holding Companies	47.53%	55.57%	41.28%
US Operating Companies	51.40%	53.38%	N/A
US Holding Companies	53.54%	54.92%	45.79%

Analytical Results: All Proxy Groups (Median)

Proxy Group	Gas Subsidiaries: Currently Authorized Equity Ratio	Gas Subsidiaries: 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Canadian Operating Companies	40.50%	41.74%	N/A
Canadian Holding Companies	49.00%	54.30%	41.41%
US Operating Companies	51.00%	52.41%	N/A
US Holding Companies	53.50%	55.24%	46.38%

Proxy Group One: Canadian Operating Companies

Company	Gas Subsidiaries: Currently Authorized Equity Ratio	Gas Subsidiaries: 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
AltaGas Utilities Inc.	39.00%	38.80%	N/A
ATCO Gas	37.00%	37.78%	N/A
Energir	38.50%	N/A	N/A
FortisBC Energy	38.50%	49.92%	N/A
Gazifere Inc.	40.00%	N/A	N/A
Heritage Gas Limited	45.00%	44.68%	N/A
Liberty Gas New Brunswick	45.00%	N/A	N/A
Pacific Northern Gas Ltd	46.50%	N/A	N/A
Pacific Northern Gas Ltd (Fort St. John	41.00%	N/A	N/A
Pacific Northern Gas Ltd (Tumbler Ridg	46.50%	N/A	N/A
Average	**41.70%**	**42.80%**	**N/A**

Proxy Group Two: Canadian Holding Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Algonquin Power & Utilities	49.00%	71.98%	49.27%
AltaGas Inc.	52.54%	54.30%	39.23%
Canadian Utilities Ltd.	37.00%	37.78%	32.27%
Emera Inc.	53.35%	63.56%	42.17%
Fortis Inc.	45.77%	50.21%	40.65%
Hydro One, Ltd.	N/A	N/A	44.10%
Average	**47.53%**	**55.57%**	**41.28%**

Proxy Group Three: US Operating Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Southern California Gas Company	52.00%	52.60%	N/A
Consumers Energy Company	NA	51.83%	N/A
Northern Illinois Gas Company	54.46%	54.81%	N/A
DTE Gas Company	51.00%	51.72%	N/A
Consolidated Edison Company of New	48.00%	46.78%	N/A
The East Ohio Gas Company	NA	60.90%	N/A
Brooklyn Union Gas Company	48.00%	52.22%	N/A
Atlanta Gas Light Company	56.00%	59.23%	N/A
Columbia Gas of Ohio, Inc.	NA	50.62%	N/A
The Peoples Gas Light and Coke Com	50.33%	53.12%	N/A
Average	**51.40%**	**53.38%**	**N/A**

Proxy Group Four: US Holding Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Atmos Energy Corporation	56.68%	58.31%	60.80%
New Jersey Resources Corporation	54.00%	55.45%	43.95%
NiSource Inc.	51.40%	55.03%	33.20%
Northwest Natural Gas Company	49.50%	49.34%	49.00%
ONE Gas, Inc.	58.78%	60.04%	48.75%
South Jersey Industries, Inc.	53.00%	54.73%	37.90%
Southwest Gas Corporation	50.79%	49.18%	45.65%
Spire, Inc.	54.16%	57.24%	47.10%
Average	**53.54%**	**54.92%**	**45.79%**

SCHEDULE 4 - Authorized Equity Ratio for Operating Companies

Proxy Group One: Canadian Operating Companies

Company	Ticker	Authorized Equity Ratio	Notes
AltaGas Utilities Inc.	N/A	39.00%	
ATCO Gas	N/A	37.00%	
Energir	N/A	38.50%	
FortisBC Energy	N/A	38.50%	
Gazifere Inc.	N/A	40.00%	
Heritage Gas Limited	N/A	45.00%	
Liberty Gas New Brunswick	N/A	45.00%	
Pacific Northern Gas Ltd	N/A	46.50%	
Pacific Northern Gas Ltd (Fort St. John/Dawsc	N/A	41.00%	
Pacific Northern Gas Ltd (Tumbler Ridge)	N/A	46.50%	
Average		**41.70%**	

Proxy Group Two: Canadian Holding Companies

Company	Ticker	State	Docket	Authorized Equity Ratio	Notes
Algonquin Power & Utilities					
New England Natural Gas Company	AQN	MA	DPU 15-75	50.00%	
Empire District Gas	AQN	MO	C-GR-2009-0434	N/A	
Midstates Natural Gas	AQN	MO	C-GR-2018-0013	N/A	
EnergyNorth Natural Gas	AQN	NH	D-DG-20-105	52.00%	
Liberty Gas New Brunswick	AQN	NB		45.00%	
Average	AQN			49.00%	
AltaGas Inc.					
ENSTAR Natural Gas Company	ALA	AK	D-U-16-066		
Washington Gas Light Company	ALA	DC	FC-1162	52.10%	
Washington Gas Light Company	ALA	MD	C-9651	52.03%	
SEMCO Energy, Inc.	ALA	MI	C-U-20479		[3]
Washington Gas Light Company	ALA	VA	C-PUE-2016-00001	53.48%	
Average	ALA			52.54%	
Canadian Utilities Ltd.					
ATCO Gas	CU	AB		37.00%	
Average	CU			37.00%	
Emera Inc.					
Peoples Gas System	EMA	FL	D-20200051	54.70%	
New Mexico Gas Company, Inc.	EMA	NM	C-19-00317-UT	52.00%	
Average	EMA			53.35%	
Fortis Inc.					
UNS Gas, Inc.	FTS	AZ	D-G-04204A-11-0158	50.82%	
Central Hudson Gas & Electric Corporation	FTS	NY	C-20-G-0429	48.00%	
FortisBC Energy	FTS	BC		38.50%	
Average	FTS			45.77%	
Hydro One, Ltd.					
N/A	H	N/A	N/A	N/A	
Average	H			N/A	
Average				**47.53%**	

Proxy Group Three: US Operating Companies

Company	Ticker	State	Docket	Equity Ratio	
Southern California Gas Company	N/A	CA	A-19-04-018	52.00%	
Consumers Energy Company	N/A	MI	C-U-21148	NA	
Northern Illinois Gas Company	N/A	IL	D-21-0098	54.46%	
DTE Gas Company	N/A	MI	C-U-20940	51.00%	[2]
Consolidated Edison Company of New York, Inc	N/A	NY	C-19-G-0066	48.00%	
The East Ohio Gas Company	N/A	OH		NA	
Brooklyn Union Gas Company	N/A	NY	C-19-G-0309	48.00%	
Atlanta Gas Light Company	N/A	GA	D-42315 (2021 Review)	56.00%	
Columbia Gas of Ohio, Inc.	N/A	OH		NA	
The Peoples Gas Light and Coke Company	N/A	IL	D-14-0225	50.33%	
	Average			**51.40%**	

Proxy Group Four: US Holding Companies

Company	Ticker	State	Docket	Authorized Equity Ratio	
Atmos Energy Corporation					
Colorado operations	ATO	CO	D-13AL-0496G	52.57%	
Georgia operations	ATO	GA	D-30442		
Kansas operations	ATO	KS	D-19-ATMG-525-RTS	56.32%	
Kentucky operations	ATO	KY	C-2021-00214	54.50%	
Louisiana operations	ATO	LA	D-U-21484 (LGS)		[1]
Mississippi operations	ATO	MS	C-U-4728		[1]
Tennessee operations	ATO	TN	D-21-00019	59.88%	
Texas operations	ATO	TX	D-GUD-10900	60.12%	
Average	ATO			56.68%	
New Jersey Resources Corporation					
New Jersey Natural Gas Company	NJR	NJ	D-GR19030420	54.00%	
Average	NJR			54.00%	
NiSource Inc.					
Northern Indiana Public Service Company	NI	IN [2]	Ca-4561	55.19%	
Columbia Gas of Kentucky, Incorporated	NI	KY	C-2021-00183	52.64%	
Columbia Gas of Maryland, Incorporated	NI	MD	C-9664	52.95%	
Columbia Gas of Ohio, Inc.	NI	OH	C-08-0072-GA-AIR		[1]
Columbia Gas of Pennsylvania, Inc.	NI	PA	D-R-2020-3018835	54.19%	
Columbia Gas of Virginia, Incorporated	NI	VA	C-PUE-2014-00020	42.01%	
Average	NI			51.40%	
Northwest Natural Holding Company					
Northwest Natural Gas Company	NWN	OR	D-UG-388	50.00%	
Northwest Natural Gas Company	NWN	WA	D-UG-181053	49.00%	
Average	NWN			49.50%	
ONE Gas, Inc.					
Kansas Gas Service Company, Inc.	OGS	KS	D-18-KGSG-560-RTS	N/A	
Oklahoma Natural Gas Company	OGS	OK	Ca-PUD202100063	58.55%	
Texas Gas Service Company, Inc.	OGS	TX	D-GUD-10928	59.00%	
Average	OGS			58.78%	
South Jersey Industries, Inc.					
South Jersey Gas Company	SJI	NJ	D-GR20030243	54.00%	
Elizabethtown Gas Company	SJI	NJ	D-GR2112154	52.00%	
Average	SJI			53.00%	
Southwest Gas Corporation					
Arizona operations	SWX	AZ	D-G-01551A-19-0055	51.10%	
California operations	SWX	CA	A-19-08-015	52.00%	
Nevada operations	SWX	NV	D-20-02023	49.26%	
Average	SWX			50.79%	
Spire, Inc.					
Spire Gulf Inc.	SR	AL	D-24794		[1]
Spire Missouri Inc.	SR	MO	C-GR-2017-0215	54.16%	
Missouri Gas Energy	SR	MO	C-GR-2017-0216	54.16%	
Average	SR			54.16%	
	Average			**53.54%**	

Notes:

[1] Most recently authorized equity ratio has been excluded because it is more than 10 years old

[2] Authorized equity ratio adjusted to exclude zero cost of capital items

[3] Michigan traditionally includes zero cost of capital items in authorized capital structures, but insufficient informaiton was provided in this proceeding to adjust the authorized equity ratio to remove zero cost of capital items.

SCHEDULE 4 - Actual Equity Ratio for Operating Companies

Proxy Group One: Canadian Operating Companies

		Total Proprietary Capital ($M)					Total Long-Term Debt ($M)					Book Equity Ratio						
Company	**Ticker**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**Equity Ratio**	**Notes**
AltaGas Utilities Inc.	N/A	$138	$139	$151	$156	$168	$200	$215	$239	$248	263	40.77%	39.19%	38.70%	38.63%	38.97%	38.80%	[6]
ATCO Gas	N/A	$991	$1,027	$1,046	$1,035	$1,066	$1,564	$1,694	$1,700	$1,715	$1,746	38.79%	37.74%	38.09%	37.65%	37.91%	37.78%	[5]
Energir	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
FortisBC Energy	N/A	$2,653	$2,740	$2,912	$2,980	$3,097	$2,376	$2,575	$2,774	$2,973	$3,123	52.75%	51.55%	51.21%	50.06%	49.79%	49.92%	[11]
Gazifere 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	N/A	N/A	N/A	N/A	N/A	
Heritage Gas Limited	N/A	$147	$150	$149	$147	N/A	$176	$182	$182	$182	N/A	45.50%	45.20%	44.98%	44.68%	N/A	44.68%	
Liberty Gas New Brunswick	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd (Fort St. John/Dawson Creek)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pacific Northern Gas Ltd (Tumbler Ridge)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Average												44.45%	43.42%	43.24%	42.75%	42.22%	42.49%	

Proxy Group Two: Canadian Holding Companies

Company	Ticker	Total Proprietary Capital ($M) 2017	2018	2019	2020	2021	Total Long-Term Debt ($M) 2017	2018	2019	2020	2021	Book Equity Ratio 2017	2018	2019	2020	2021	Avg. Book Equity Ratio	
Algonquin Power & Utilities																		
Liberty Utilities (New England Natural Gas Company) (	AQN	$71	$81	$93	$103	$123	$34	$34	$34	$27	$27	67.74%	70.67%	73.37%	79.05%	81.85%	80.45%	[11]
Empire District Gas Company	AQN	$32	$33	$34	$35	$59	$57	$55	$55	$55	$55	35.66%	37.28%	38.39%	38.60%	51.55%	45.08%	[11]
Liberty Utilities (Midstates Natural Gas) Corp	AQN	$103	$110	$115	$121	$123	$0	$0	$0	$0	$0						N/A	[7]
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	$169	$179	$185	$194	N/A	$159	$159	$159	$159	N/A	51.47%	52.96%	53.72%	54.95%	N/A	54.95%	[11]
Liberty Gas New Brunswick	AQN	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	[10]
Average	AQN	$374	$403	$427	$453	$305	$250	$248	$248	$242	$82	59.93%	61.91%	63.25%	65.23%	78.74%	71.98%	
AltaGas Inc.																		
SEMCO Energy, Inc.	ALA	N/A	$306	N/A	N/A	N/A	N/A	$196	N/A	N/A	N/A	N/A	60.92%	N/A	N/A	N/A	N/A	[8]
Washington Gas Light Company	ALA	$1,324	$1,591	$1,574	$1,851	N/A	$1,093	$1,043	$1,442	$1,558	N/A	54.78%	60.40%	52.20%	54.30%	N/A	54.30%	[11]
Average	ALA	$1,324	$1,897	$1,574	$1,851	$0	$1,093	$1,240	$1,442	$1,558	$0	54.78%	60.48%	52.20%	54.30%	N/A	54.30%	
Canadian Utilities Ltd.																		
ATCO Gas	CU	$991	$1,027	$1,046	$1,035	$1,066	$1,564	$1,694	$1,700	$1,715	$1,746	38.79%	37.74%	38.09%	37.65%	37.91%	37.78%	[5]
Average	CU	$991	$1,027	$1,046	$1,035	$1,066	$1,564	$1,694	$1,700	$1,715	$1,746	38.79%	37.74%	38.09%	37.65%	37.91%	37.78%	
Emera Inc.																		
Peoples Gas System	EMA	$394	$436	$531	$662	$786	$261	$311	$336	$336	$518	60.09%	58.39%	61.29%	66.36%	60.27%	63.31%	[11]
New Mexico Gas Company, Inc.	EMA	$669	$671	$682	$752	N/A	$281	$277	$369	$366	N/A	70.45%	70.77%	64.88%	67.30%	N/A	67.30%	[11]
Average	EMA	$1,063	$1,108	$1,213	$1,414	$786	$542	$588	$705	$701	$518	66.22%	65.31%	63.26%	66.86%	60.27%	63.56%	
Fortis Inc.																		
UNS Gas, Inc.	FTS	$103	$105	$114	$121	$130	$94	$94	$94	$94	$95	52.12%	52.66%	54.62%	56.06%	57.93%	56.99%	[9]
Central Hudson Gas & Electric Corporation	FTS	$627	$697	$773	$853	$932	$599	$674	$747	$837	$923	51.15%	50.84%	50.84%	50.46%	50.25%	50.36%	[11]
FortisBC Energy	FTS	$2,653	$2,740	$2,912	$2,980	$3,097	$2,376	$2,575	$2,774	$2,973	$3,123	52.75%	51.55%	51.21%	50.06%	49.79%	49.92%	[11]
Average	FTS	$3,383	$3,542	$3,798	$3,953	$4,159	$3,069	$3,343	$3,615	$3,904	$4,140	52.43%	51.44%	51.23%	50.31%	50.11%	50.21%	
Hydro One, Ltd.																		
N/A	H	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Average	H	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A	N/A	N/A	
Average																	**55.57%**	

Proxy Group Three: US Operating Companies

		Total Proprietary Capital ($M)					Total Long-Term Debt ($M)					Book Equity Ratio						
Company	**Ticker**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**Equity Ratio**	
Southern California Gas Company	N/A	$3,908	$4,258	$4,748	$5,144	$5,442	$3,002	$3,452	$3,802	$4,763	$4,773	56.55%	55.23%	55.53%	51.92%	53.27%	52.60%	[11], [12]
Consumers Energy Company	N/A	$6,489	$6,921	$7,738	$8,557	$9,280	$5,896	$6,809	$7,263	$8,131	$8,438	52.40%	50.41%	51.58%	51.28%	52.38%	51.83%	[11]
Northern Illinois Gas Company	N/A	$1,186	$1,504	$1,875	$2,315	$2,533	$1,024	$1,324	$1,574	$1,899	$2,099	53.66%	53.19%	54.36%	54.94%	54.68%	54.81%	[11]
DTE Gas Company	N/A	$1,476	$1,668	$1,853	$2,024	$2,236	$1,330	$1,550	$1,710	$1,910	$2,065	52.61%	51.84%	52.01%	51.45%	51.99%	51.72%	[11]
Consolidated Edison Company of New York, Inc.	N/A	$12,439	$12,910	$14,147	$14,849	$16,312	$13,358	$14,258	$15,079	$16,919	$18,527	48.22%	47.52%	48.41%	46.74%	46.82%	46.78%	[11]
The East Ohio Gas Company	N/A	$1,540	$1,728	$2,496	$2,703	$2,867	$1,415	$1,300	$1,665	$1,787	$1,787	52.11%	57.07%	59.98%	60.20%	61.60%	60.90%	[11]
Brooklyn Union Gas Company	N/A	$1,948	$2,007	$2,698	$2,786	$3,465	$1,230	$1,650	$2,650	$2,650	$3,050	61.29%	54.89%	50.45%	51.25%	53.19%	52.22%	[11]
Atlanta Gas Light Company	N/A	$1,478	$1,682	$1,820	$2,080	$2,253	$1,228	$1,180	$1,287	$1,427	$1,555	54.62%	58.77%	58.59%	59.30%	59.17%	59.23%	[11]
Columbia Gas of Ohio, Inc.	N/A	$1,233	$1,590	$1,593	$1,744	$1,964	$1,163	$1,333	$1,413	$1,713	$1,903	51.46%	54.40%	53.00%	50.45%	50.79%	50.62%	[11]
The Peoples Gas Light and Coke Company	N/A	$1,215	$1,459	$1,651	$1,953	$2,054	$1,050	$1,195	$1,520	$1,670	$1,870	53.64%	54.98%	52.06%	53.90%	52.34%	53.12%	[11]
Average																	**53.38%**	

Proxy Group Four: US Holding Companies

		Total Proprietary Capital ($M)					Total Long-Term Debt ($M)					Book Equity Ratio						
Company	**Ticker**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**Equity Ratio**	
Atmos Energy Corporation																		
Atmos Energy Corporation	ATO	$4,564	$5,348	$6,128	$7,213	N/A	$3,089	$3,111	$4,359	$5,157	N/A	59.63%	63.22%	58.43%	58.31%	N/A	58.31%	[11]
Weighted Average	ATO	$4,564	$5,348	$6,128	$7,213	$0	$3,089	$3,111	$4,359	$5,157	$0	59.63%	63.22%	58.43%	58.31%	N/A	58.31%	
New Jersey Resources Corporation																		
New Jersey Natural Gas Company	NJR	$906	$1,093	$1,278	$1,360	N/A	$547	$672	$893	$1,093	N/A	62.35%	61.92%	58.87%	55.45%	N/A	55.45%	[11]
Weighted Average	NJR	$906	$1,093	$1,278	$1,360	$0	$547	$672	$893	$1,093	$0	62.35%	61.92%	58.87%	55.45%	N/A	55.45%	
NiSource Inc.																		
Northern Indiana Public Service Company	NI	$2,512	$2,771	$2,918	$3,210	$3,536	$1,774	$2,144	$2,253	$2,324	$2,499	58.60%	56.37%	56.43%	58.01%	58.59%	58.30%	[11]
Columbia Gas of Kentucky, Incorporated	NI	$133	$153	$169	$186	N/A	$114	$127	$142	$154	N/A	53.76%	54.62%	54.23%	54.68%	N/A	54.68%	[11]
Columbia Gas of Maryland, Incorporated	NI	$56	$65	$77	$86	N/A	$48	$49	$70	$70	N/A	54.06%	56.70%	52.38%	54.95%	N/A	54.95%	[11]
Columbia Gas of Ohio, Inc.	NI	$1,233	$1,590	$1,593	$1,744	$1,964	$1,163	$1,333	$1,413	$1,713	$1,903	51.46%	54.40%	53.00%	50.45%	50.79%	50.62%	[11]
Columbia Gas of Pennsylvania, Inc.	NI	$736	$886	$983	$1,125	$1,320	$626	$706	$786	$896	$1,036	54.04%	55.68%	55.59%	55.68%	56.05%	55.86%	[11]
Columbia Gas of Virginia, Incorporated	NI	$270	$277	$315	$358	N/A	$356	$371	$426	$461	N/A	43.15%	42.71%	42.53%	43.69%	N/A	43.69%	[11]
Weighted Average	NI	$4,940	$5,742	$6,057	$6,709	$6,821	$4,081	$4,731	$5,091	$5,618	$5,437	54.76%	54.83%	54.33%	54.43%	55.64%	55.03%	
Northwest Natural Holding Company																		
Northwest Natural Gas Company	NWN	N/A	$720	$823	$835	$978	N/A	$710	$775	$865	$995	N/A	50.36%	51.50%	49.11%	49.57%	49.34%	[11]
Average	NWN	$0	$720	$823	$835	$978	$0	$710	$775	$865	$995	N/A	50.36%	51.50%	49.11%	49.57%	49.34%	
ONE Gas, Inc.																		
Kansas Gas Service Company, Inc.	OGS	$617	$691	$733	$740	N/A	$357	$420	$421	$487	N/A	63.35%	62.20%	63.55%	60.33%	N/A	60.33%	[2]
Oklahoma Natural Gas Company	OGS	$679	$770	$857	$889	N/A	$397	$473	$501	$597	N/A	63.13%	61.94%	63.10%	59.85%	N/A	59.85%	[3]
Texas Gas Service Company, Inc.	OGS	$626	$720	$767	$822	N/A	$368	$442	$446	$548	N/A	63.01%	61.95%	63.23%	59.99%	N/A	59.99%	[11]
Average	OGS	$1,923	$2,181	$2,357	$2,452	$0	$1,121	$1,335	$1,368	$1,632	$0	63.16%	62.03%	63.28%	60.04%	N/A	60.04%	
South Jersey Industries, Inc.																		
South Jersey Gas Company	SJI	$921	$1,008	$1,090	$1,304	N/A	$765	$875	$547	$1,078	N/A	54.63%	53.55%	66.58%	54.73%	N/A	54.73%	[1]
Average	SJI	$921	$1,008	$1,090	$1,304	$0	$765	$875	$547	$1,078	$0	54.63%	53.55%	66.58%	54.73%	N/A	54.73%	
Southwest Gas Corporation																		
Southwest Gas Corporation	SWX	$1,610	$1,782	$2,005	$2,233	$2,528	$1,527	$1,827	$2,002	$2,452	$2,458	51.32%	49.38%	50.03%	47.66%	50.70%	49.18%	[11]
Average	SWX	$1,610	$1,782	$2,005	$2,233	$2,528	$1,527	$1,827	$2,002	$2,452	$2,458	51.32%	49.38%	50.03%	47.66%	50.70%	49.18%	
Spire, Inc.																		
Spire Gulf Inc.	SR	$44	$51	$60	$70	$80	$61	$62	$101	$101	$82	41.74%	45.31%	37.18%	40.69%	49.48%	45.09%	[4]
Spire Missouri Inc.	SR	$1,171	$1,260	$1,339	$1,435	$1,578	$879	$829	$929	$1,097	$1,346	57.13%	60.32%	59.05%	56.68%	53.96%	55.32%	[11]
Spire Alabama Inc.	SR	$867	$809	$830	$852	$882	$248	$323	$372	$472	$571	77.78%	71.48%	69.04%	64.35%	60.68%	62.52%	[11]
Average	SR	$2,082	$2,120	$2,229	$2,356	$2,540	$1,188	$1,213	$1,402	$1,670	$1,999	63.68%	63.60%	61.38%	58.52%	55.95%	57.24%	
			Average									**58.50%**	**57.36%**	**58.05%**	**54.78%**	**52.97%**	**54.92%**	

Notes:

[1] 2019 & 2020 Source: South Jersey Gas 2020 FERC Form 2, at 112
[2] 2019 & 2020 Source: Kansas Gas Service 2020 FERC Form 2, at 112
[3] 2019 & 2020 Source: Oklahoma Natural Gas Company 2020 FERC Form 2, at 112
[4] 2020 & 2021 Source: Spire Gulf Inc. 2020 FERC Form 2, at 110 and 114
[5] ATCO Gas Finance and Operations Reports to the Alberta Utilities Commission, 2016-2021, Schedule 11
[6] AltaGas Canada distribution Finance and Operations Reports to the Alberta Utilities Commission, 2016-2021
[7] Midstates Natural Gas is excluded from the analysis because S&P Capital IQ Pro does not report data regarding its long-term debt
[8] Michigan Public Service Commission Case No. U-20479, SEMCO Energy Gas Company application, Exhibit No. A-2 (BHF-6), Schedule B-4
[9] UNS Gas Annual Reports to the Arizona Corporation Commission, Financial Statements, at 4
[10] Liberty Gas New Brunswick's Regulatory Financial Statements, Note 13. 2019 data is excluded because Liberty Gas New Brunswick no longer carried long-term debt as of June 30, 2019.
[11] S&P Capital IQ
[12] 2020 and 2021 data from Southern California Gas Company 2021 Statement of Operations

SCHEDULE 4 - Equity Ratio for Holding Companies

Proxy Group Two: Canadian Holding Companies

Company	Ticker	2017	2018	2019	2020	2021	2-Year Avg.	Source
Algonquin Power & Utilities	AQN	43.70%	45.95%	47.28%	51.52%	47.01%	49.27%	*Annual Reports*
AltaGas Inc.	ALA	40.20%	35.68%	42.22%	39.69%	38.78%	39.23%	*Annual Reports*
Canadian Utilities Ltd.	CU	32.59%	31.32%	33.45%	32.78%	31.76%	32.27%	*Annual Reports*
Emera Inc.	EMA	35.04%	36.79%	38.51%	42.72%	41.61%	42.17%	*Value Line, June 17, 2022*
Fortis Inc.	FTS	37.10%	37.20%	41.80%	40.50%	40.80%	40.65%	*Value Line, June 10, 2022*
Hydro One, Ltd.	H	48.22%	45.14%	44.07%	43.77%	44.43%	44.10%	*Annual Reports*
Average		**39.47%**	**38.68%**	**41.22%**	**41.83%**	**40.73%**	**41.28%**	

Proxy Group Four: US Holding Companies

Company	Ticker	2017	2018	2019	2020	2021	2-Year Avg.	Source
Atmos Energy Corporation	ATO	56.00%	65.70%	62.00%	60.00%	61.60%	60.80%	*Value Line, May 27, 2022*
New Jersey Resources Corporation	NJR	55.40%	54.60%	50.20%	44.90%	43.00%	43.95%	*Value Line, May 27, 2022*
NiSource Inc.	NI	36.50%	37.90%	36.90%	32.90%	33.50%	33.20%	*Value Line, May 27, 2022*
Northwest Natural Gas Company	NWN	52.10%	51.90%	51.80%	50.80%	47.20%	49.00%	*Value Line, May 27, 2022*
ONE Gas, Inc.	OGS	62.20%	61.40%	62.30%	58.50%	39.00%	48.75%	*Value Line, May 27, 2022*
South Jersey Industries, Inc.	SJI	51.50%	37.60%	40.80%	37.40%	38.40%	37.90%	*Value Line, May 27, 2022*
Southwest Gas Corporation	SWX	50.20%	51.70%	52.10%	49.50%	41.80%	45.65%	*Value Line, May 27, 2022*
Spire, Inc.	SR	50.00%	54.30%	55.00%	51.00%	43.20%	47.10%	*Value Line, May 27, 2022*
Average		**51.74%**	**51.89%**	**51.39%**	**48.13%**	**43.46%**	**45.79%**	

SCHEDULE 5 - Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI Change		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1990	-18.7	-4.9	-1.6	-1.4	0.2	1.9	4.8	5.4	10.7	8.5		1.4	8.2	5.6	1.17
1991	8.4	31.9	-3.5	25.0	-2.1	-0.1	5.6	4.2	9.5	7.9		1.4	10.3	6.9	1.15
1992	-4.1	7.6	2.1	7.2	0.9	3.5	1.5	3.0	8.1	7.0		1.4	11.2	7.5	1.21
1993	32.2	10.1	16.3	13.4	2.7	2.8	1.9	3.0	7.2	5.9		1.5	11.4	6.9	1.29
1994	-1.3	1.2	3.8	-11.1	4.5	4.0	0.2	2.6	8.4	7.1		1.6	10.4	6.1	1.37
1995	15.1	37.6	-2.0	32.0	2.7	2.7	2.1	2.8	8.2	6.6		1.7	9.5	5.6	1.37
1996	26.7	22.0	17.5	5.2	1.6	3.8	1.6	3.0	7.2	6.4		1.7	9.6	5.4	1.36
1997	15.3	34.0	32.1	25.7	4.3	4.4	1.6	2.3	6.1	6.3	19.2	1.8	9.1	4.9	1.38
1998	-2.0	27.9	-0.2	15.3	3.9	4.5	1.0	1.6	5.3	5.3	20.5	1.7	8.3	4.5	1.48
1999	30.4	21.1	-30.8	-9.2	5.2	4.8	1.7	2.2	5.6	5.6	22.4	1.7	7.6	4.2	1.49
2000	10.1	-4.6	42.1	61.2	5.2	4.1	2.7	3.4	5.9	6.0	24.7	1.7	6.8	4.0	1.49
2001	-9.3	-9.3	7.3	-27.8	1.8	1.0	2.5	2.8	5.5	5.0	23.8	1.5	7.2	4.7	1.55
2002	-11.9	-22.6	3.4	-30.9	3.0	1.7	2.3	1.6	5.3	4.6	22.8	1.5	7.7	5.8	1.57
2003	24.2	24.5	23.4	23.3	1.8	2.8	2.8	2.3	4.8	4.0	21.2	1.5	7.6	6.0	1.40
2004	13.4	11.2	8.7	24.3	3.1	3.9	1.9	2.7	4.6	4.3	21.9	1.6	7.2	5.5	1.30
2005	25.4	7.0	37.6	19.2	3.2	3.5	2.2	3.4	4.1	4.3	22.3	1.6	6.8	5.1	1.21
2006	15.5	13.9	5.9	18.7	2.6	2.8	2.0	3.2	4.2	4.8	21.3	1.7	6.3	4.6	1.13
2007	11.6	5.7	11.9	18.9	2.1	2.0	2.1	2.8	4.3	4.6	20.6	1.7	6.1	4.6	1.07
2008	-33.5	-36.1	-20.3	-28.0	1.0	0.0	2.4	3.8	3.6	3.6	21.2	1.8	6.2	5.8	1.07
2009	31.3	22.6	16.1	9.4	-2.9	-2.4	0.3	-0.4	3.2	3.2	16.0	1.4	8.4	9.3	1.14
2010	16.3	13.2	18.6	5.2	3.1	2.5	1.8	1.6	3.2	3.2	17.0	1.7	8.1	9.6	1.03
2011	-8.5	1.1	6.0	18.7	3.1	1.8	2.9	3.2	2.8	2.8	18.3	1.8	7.6	8.9	0.99
2012	4.9	14.2	3.3	3.0	1.8	2.2	1.5	2.1	1.9	1.8	18.4	1.8	7.4	8.1	1.00
2013	12.0	29.1	-4.9	11.2	2.3	1.8	0.9	1.5	2.3	2.3	19.1	1.8	7.1	7.4	1.03
2014	10.7	14.7	16.2	31.0	2.9	2.1	1.9	1.6	2.2	2.5	20.9	1.8	7.0	6.2	1.10
2015	-9.2	1.4	-4.4	-5.4	0.7	2.9	1.1	0.1	1.5	2.1	20.5	1.5	6.9	5.3	1.28
2016	21.9	13.7	18.7	16.6	1.0	1.7	1.4	1.3	1.3	1.8	20.1	1.4	7.1	4.9	1.33
2017	8.3	20.8	10.9	9.1	3.0	2.3	1.6	2.1	1.8	2.3	20.4	1.5	6.4	4.4	1.30
2018	-8.9	-4.4	-8.9	4.1	2.8	3.0	2.3	2.4	2.3	2.9	21.0	1.5	5.9	3.9	1.30
2019	23.5	31.8	38.2	25.7	1.9	2.3	1.9	1.8	1.6	2.1	21.1	1.4	5.8	3.7	1.33
2020	5.6	18.4	15.3	0.5	-5.2	-3.4	0.7	1.2	0.8	0.9	18.8	1.2	9.6	8.1	1.34
2021	25.2	28.7	11.6	17.7	4.5	5.7	3.4	4.7	1.4	1.4	n/a	1.3	7.4	5.4	1.25
25-year Avg.	8.96	10.85	10.54	9.81	2.13	2.23	1.81	2.15	3.65	3.72	20.56	1.61	7.34	5.79	1.27
10-year Avg.	6.03	14.07	9.03	11.46	1.42	1.66	1.64	1.73	1.84	2.16	19.86	1.56	7.06	6.07	1.20
5-year Avg.	10.07	16.05	14.83	11.21	0.69	1.16	1.59	1.78	1.53	2.02	20.28	1.39	6.94	4.98	1.32
Correlation	0.71		0.60		0.87		0.62		0.98		0.05		0.42		--
							Consensus Forecasts [15]								
2023					2.80	2.20	2.50	3.20	2.70	2.80					
2024					2.1	1.8	2.2	2.4	3.1	3.2					
2025					2	2.2	2.1	2.4	3.2	3.4					

Notes:
[1] Source:Bloomberg Professional; total return index gross dividend yield
[2] Source:Bloomberg Professional; total return index gross dividend yield
[3] Source:Bloomberg Professional; total return index gross dividend yield
[4] Source:Bloomberg Professional; total return index gross dividend yield
[5] Source: Statistics Canada. Table 36-10-0104-01 Gross domestic product, expenditure-based, Canada
[6] Source: Bureau of Economic Analysis, Table 1.1.5. Gross Domestic Product
[7] Source: Statistics Canada; Consumer Price Index (2002=100), All items, not seasonally adjusted, accessed February 26, 2021
[8] Source: U.S. Bureau of Labor Statistics; CPI-All Urban Consumers (1982-84=100), all items, not seasonally adjusted, accessed February 26, 2021
[9] Source: Bank of Canada
[10] Source: Bloomberg Professional
[11] Source: Statistics Canada, Imports, exports and trade balance of goods by country and Gross domestic product, expenditure-based;
United States Census Bureau (https://www.census.gov/foreign-trade/balance/c1220.html); Bureau of Economic Analysis; Table 1.1.5
[12] Source: Statistics Canada; Labour force survey estimates (LFS), unemployment rate, 15 years and over, seasonally adjusted, accessed February 26, 2021
[13] Source: U.S. Bureau of Labor Statistics, Unemployment Rate, seasonally adjusted, accessed February 26, 2021
[14] Source: Federal Reserve Economic Data, as of February 22, 2021
[15] Source: Consensus Forecasts, Survey Date April 11, 2022