EB-2024-0063

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

N-M4 Interrogatory Response Attachments

Table of Contents

Attachment 1: The 2023 Enbridge Gas Inc. rebasing proceedings (OEB EB-2022-0200)

Enbridge Gas Inc.

Application to change its natural gas rates and other charges beginning January 1, 2024

Evidence of Dr. Sean Cleary, CFA Professor of Finance

Sponsored by Industrial Gas Users Association

TABLE OF CONTENTS

1. INTRODUCTION

1.1. Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am a Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta on several occasions including generic cost of capital proceedings in 2013-2014 (Proceeding ID 2191), 2015-2016 (Proceeding ID 20622), 2018 (Proceeding ID 22570), 2019-20 (Proceeding ID 24110), 2022-23 (Proceeding ID 27084), as well as the generic regulated rate option proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan proceeding (Proceeding ID 22357) in 2017. I also prepared evidence on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016, and in 2018.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of over 30 publications. My work has been cited more than 5,000 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of capital issues. I have authored or co-authored 14 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Attachment A to my evidence.

1.2. Purpose of Testimony

My evidence is sponsored by IGUA. In this capacity, I was asked to prepare expert testimony in relation to the request by Enbridge Gas Inc. (EG) in the 2024-2028 Natural Gas Distribution Rates Application (OEB Case # EB-2022-0200) to increase their allowed equity ratio from its current level of 36 percent.

I acknowledge that I have a duty to provide opinion evidence to the OEB that is fair, objective and non-partisan; and, further that my evidence would not change if I was retained by any other parties involved in this Proceeding. A signed copy of the OEB's Form A, Acknowledgement of Expert's Duty, is attached as Attachment B to this evidence.

1.3. Summary of Equity Ratio Recommendations

I recommend maintaining Enbridge Gas' (EG) existing equity ratio at 36%. Concentric has simply failed to provide any compelling evidence that it should be increased. My analysis strongly supports that such an increase, which would be borne by EG's customers, is simply not necessary. Concentric has not provided meaningful support for its assertion that there has been a significant increase in EG's risk profile that would warrant any increase in its equity ratio, let alone the significant increase requested. Recent debt rating reports confirm this assertion, by providing solid (A and A-) and "stable" ratings, which were based on the assumption of a 36% equity ratio during the test period. These reports noted that ESG factors (including transition risks) are immaterial with respect to EG's current risk profile, and they continue to view EG's low business risk profile as its #1 strength.

Concentric's approach of simply comparing EG's equity ratio to average awarded equity ratios at various times in the past in other jurisdictions is flawed by design. Such an approach ignores the more relevant current market conditions facing EG today. Equally as important, simply referencing existing awarded ratios in other jurisdictions that were determined at various times in the past, and without providing knowledge of the evidence of record at the time, including both existing market conditions, as well as the risk profile of the utilities in question, does not provide meaningful information – at least not without providing additional and detailed information to provide context.

Such an approach is even less informative when three of the four proxy groups used by Concentric are not "similar risk" comparator groups, and the fourth group consists of only three of 10 legitimate comparable companies; albeit these three are also much smaller than EGI and require risk adjustments for this fact, as previously argued by Mr. Coyne of Concentric in his 2021 evidence provided in New Brunswick.[1] My discussion and analysis in Section 3 confirms the low risk nature of EG, while Sections 4.1-4.3 confirm that EG possesses total risk that is much lower than the utilities included in both of Concentric's US proxy groups, as well

[1] Source: Attachment C, "James Coyne Testimony on behalf of Liberty Utilities (Gas New Brunswick) ZP, March 31, 2021, Figure 31, page 70.

as the Canadian holding company proxy group. The only potentially valid (i.e., similar risk) proxy group used by Concentric is the Canadian operating company group; although Section 4.4 demonstrates that seven of the 10 companies included in that sample are not legitimate comparators due to their *extremely* small size, while the remaining three are also less than 5% of the size of EG, which should be adjusted for in interpreting related statistics.

The more appropriate approach is to determine the awarded equity ratio for EG on an "absolute basis," with respect to its business and financial risk profiles. Section 3 demonstrates that EG possesses very low risk, much lower than that faced by utilities in three of Concentric's proxy groups, and than seven of 10 utilities included in Concentric's Canadian OpCo proxy group (as demonstrated in Section 4). Section 3 shows that EG faces extremely low business risk, as noted by the debt rating agencies. It also shows that EG displays very low total risk as evidenced by its ability to consistently earn ROEs in excess of its allowed ROEs, and that it displays low variability in earned ROEs – both of which are bottom line measures of total risk.

With respect to an absolute assessment of EG's risk, Section 5 further shows that at a 36% equity ratio, the credit metrics for EG are forecast to improve over the test period, and in fact will exceed the metric estimates used by S&P in determining its "stable" assessment for EG's rating. In other words, at a 36% equity ratio level, the credit metrics are **more than adequate**. Further, there is nothing in either DBRS' or S&P's financial risk analysis, or their business risk assessments (i.e., excellent), to indicate that either rating agency is uncomfortable with EG's existing equity ratio of 36%. In short, there is clearly no need for an increase in EG's equity ratio to maintain its current strong credit ratings (i.e., financial integrity), or its ability to continue to access capital at favorable rates.

Aside from the broader issues discussed above with respect to the inappropriateness of Concentric's general approach of simply comparing awarded equity ratios in other jurisdictions to EG's awarded equity ratio, as well as the fact that they do not provide reasonable comparators, there are other flaws and deficiencies in Concentric's assertions as I demonstrate in Section 6. In particular, in response to information requests, Concentric provided no compelling support for their assertions that; i) EG faces greater risks due to its lack of geographic and regulatory diversification and assets which are newer and less depreciated than the assets of other utilities; ii) gas utilities trade at a discount to electric utilities; and iii)

Canadian utilities trade at a greater discount to US utilities in 2022 versus 2012, due to an increase in their risk profile.

2. SYNOPSIS OF CONCENTRIC'S ANALYSIS

On page 8 of Concentric's evidence, it provides the following description of the Fair Return Standard (FRS) by the former National Energy Board (NEB) in its Trans Québec & Maritimes Pipelines Inc. RH-1-2008 Decision, at pp. 6-7 (emphasis added):

> *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**).*

Section 5 of Concentric's evidence conducts what it refers to as a "Fair Return Standard Analysis," which is mainly based on the comparison of EG's equity ratios and a few other factors to those of four proxy groups of Canadian and U.S. utilities it constructs. Such a cursory approach does not provide compelling evidence to support an increase in EG's equity ratio, since it is not reflective of current market conditions. In addition, the allowed equity ratios convey little information without knowing the details of the record underlying those decisions, including the regulatory, business and financial risks facing the utilities to which they apply.

My evidence shows that three of the four proxy groups are not very good "comparables" in the sense of representing "enterprises of like risk," while the fourth group (the Canadian Operating Company sample) includes seven poor comparators, leaving only three legitimate comparator companies. Concentric itself (page 79) concedes that the operating companies in its proxy groups are the "most applicable," yet it did not respond to information requests that asked specifically how the various proxy group results were weighted.

In addition to concerns regarding the comparability of the proxy groups as constructed, Concentric further muddied the waters for valid comparisons by using variations of these proxy groups for various purposes - at times adding new companies to the groups without providing any explanation for doing so. For example, Figure 38 of Concentric's evidence references the data for 55 US operating companies, but this information includes data for **only three** of the 10 US operating companies included in the US Operating Companies Proxy Group, and therefore it includes data for 52 US operating utilities that were specifically excluded from Concentric's US OpCo proxy group. As another example, I would note that in determining the average P/E ratios, P/B ratios, betas and debt ratings for Canadian and US gas utilities it reported in Figure 22, Concentric included the six utilities included in its Canadian Holding Company sample, but also included Enbridge Inc. and TC Energy Corporation – two utilities that Concentric specifically excluded in constructing the Canadian HoldCo proxy group. Similarly, Concentric included the eight US utilities included in the US HoldCo sample, but also included Chesapeake Utilities Corporation and UGI Corporation – two utilities that were specifically excluded in constructing the US HoldCo proxy group. So even if the four proxy groups assembled by Concentric were indeed good comparators (although they are not), Concentric is not consistent in terms of what utilities within those proxy groups it actually provides statistics that it relies upon to provide support for its analyses.

Relatedly, Concentric's credit metric analysis is based on the metrics of 13 of the 14 companies included in the two HoldCo samples, but it does not report or rely on metrics for the 10 companies included in the Canadian OpCo group (the most comparable proxy group), and uses only seven of the 10 companies included in the US OpCo group. In other words, the credit metric analysis heavily weights (i.e., uses 13 of 14) holding companies, and provides a much lower weighting to operating utilities (i.e., uses only seven of 20), despite Concentric's acknowledgement that the operating companies are the "most applicable."

In addition to pointing out the deficiencies in Concentric's chosen proxy groups in terms of representing "enterprises of like risk," my evidence further shows that it is not necessary to increase EG's equity ratio for reasons of financial integrity or the ability to attract capital. These conclusions are based on an examination of EG's business risk, its ability to earn its allowed ROE, as well as an examination of debt ratings, debt rating reports, EG's cost of debt relative to comparable utilities, and credit metric analysis.

On page 10 of its evidence, Concentric notes that in 2009 the OEB suggested that (emphasis added) 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." I do not believe that the evidence provided by EG is compelling enough to suggest that such a significant change in business or financial risk has occurred for EG. Recent debt rating reports from both DBRS and S&P support my view and indicate no change in EG's business risk, and that EG's credit metrics remain acceptable, based on the assumption that the equity ratio remains *unchanged*. In addition, both the DBRS and S&P rating reports suggest the impact from environmental factors (and in fact all ESG factors) is neutral, and it seems to be more of a long-term concern. Finally, as pointed out on page 12 of Concentric's evidence (emphasis added):

> *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.*

3. ENBRIDGE GAS RISK ANALYSIS

3.1 EG Debt Rating Reports

Recent debt rating reports identify **low business risk** (S&P) or **low-risk regulated operations** (DBRS) as the #1 strength for EG, which is consistent with its regulated operations as a virtual monopoly in a well-defined and economically strong region with strong regulatory support, and where it can reasonably pass on legitimate costs to its customers.

Consider first the following information obtained from EG's DBRS Morningstar (DBRS) debt rating report of September 27, 2022,[2] which confirmed its rating of **A and stable**. DBRS suggested that this rating reflected the following considerations (emphasis added):

1. "*EGI maintained a **stable business risk profile…"***
2. "*EGI's **financial performance remained solid, with improved credit metrics** for the 12 months ended June 30, 2022. Furthermore, DBRS*

[2] Included in Exhibit I.1.8-STAFF-14, Attachment 5.

> *Morningstar* ***expects the credit metrics to improve*** *modestly over the medium term as a result of rate base growth and synergy realization…"*
>
> 3. *"EGI's* ***liquidity remained solid…"***

DBRS went on to note (emphasis added) that:

> *The Company's ratings are* ***supported by a stable regulatory framework in Ontario*** *and* ***a very large and economically strong base of approximately 3.8 million customers across the province—the largest in Canada and one of the largest in North America****. This* ***large customer base is one of the key factors*** *allowing EGI to achieve* ***operating efficiency*** *under the price-cap IR.* ***Good synergy*** *was realized in the past three years from the amalgamation of Enbridge Gas Distribution Inc. (EGD) with Union Gas Limited (Union Gas), and DBRS Morningstar* ***expects significant synergy to be achieved through 2023****. EGI's* ***reliability and the flexibility of its natural gas supply have improved significantly****, compared with standalone EGD, as a result of the significant addition of Union Gas's storage facilities. The ratings incorporate EGI's exposure to volume risk and the potential regulatory lag in the recovery of natural gas costs when the price of natural gas increases substantially.*

DBRS identifies the following strengths for EG (emphasis added):

1. ***Low-risk regulated operations***

   Almost all of EGI's assets are regulated and operate under the 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*** *(see the Regulatory Update section); (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.***

2. ***Strong franchise area with a very large customer base***

   EGI is currently the ***largest regulated natural gas distributor in Canada and is one of the largest in North America, serving approximately 3.8 million***

***residential, commercial, and industrial customers across Ontario**. The Company's **service area is viewed as economically strong compared with other service areas in Canada**. EGI's **large customer base provides it with the size and scale to operate efficiently** during the five-year price-cap IR plan. EGI's **large size also allows it to maintain a good degree of flexibility with its capex planning**.*

*3. **Sizable storage assets provide additional rate base and cash flow**.*

It is interesting to note from the comments above that DBRS considers operating in Ontario, in a *"stable regulatory framework"* and in an *"economically strong"* service area as strengths, and not a weakness, as has been argued by Concentric. I agree with DBRS' interpretation.

DBRS also notes the following potential challenges:

1. Volume risk
2. Managing operating costs under the price-cap IR plan
3. Potential regulatory lag

In its summary, DBRS noted that **all of EG's credit metrics remained solid**, *"reflecting relatively stable cash flow and reasonable debt leverage."* This observation was based on the observation that *"EGI's financing plan has been to maintain the debt-to-capital ratio **in line with the regulatory capital structure of 64% debt/36% equity**."* So in other words, DBRS did not express concerns regarding EG's current allowed equity ratio of 36%.

Finally, DBRS states that *"There are **currently no environmental, social, or governance (ESG) factors affecting the ratings of EGI."*** The ESG factors considered by DBRS include five environmental factors, including the following three:

- Emissions, effluents and wastes
- Carbon and GHG costs
- Climate and Weather risks

Obviously, DBRS did not share the same concerns as Concentric regarding there being a significant increase in EG's risk profile due to these factors.

EG's S&P debt rating report of July 21, 2022,[3] also confirmed EG's rating from S&P, which remained at **A- and stable**. This rating was supported by an Excellent Business Risk rating and a Significant Financial Risk Rating.

In this report, S&P noted the following key strengths and weaknesses:

Key strengths

1. Low-risk, rate-regulated natural gas distribution and transmission company.
2. Derives about two-thirds of its distribution revenue from residential and small business customers, which provide stable cash flows.
3. Passes commodity costs through to customers and recovers costs through a quarterly adjustment mechanism, which limits its exposure to commodity risk.

Key risks

1. Operates only in Ontario, thus it has limited geographic and regulatory diversity.
2. Negative discretionary cash flow due to increasing capital expenditure activities indicates external funding needs.

S&P added the following comments:

- ***"We expect Enbridge Gas Inc. (EGI) to maintain its financial performance throughout our two-year outlook period. …"***
- ***"EGI continues to operate in a credit supportive regulatory framework…"***
- ***"EGI lacks geographic and regulatory diversity.*** *The company operates only in Ontario, is the largest gas distributor in Ontario, and serves virtually all of the province's approximately 3.8 million residential, commercial, and industrial customers. However, compared with other utilities, EGI lacks geographic and regulatory diversity, which makes it reliant on the OEB's regulation to sustain its credit quality."*

The first two statements are consistent with the low-risk nature of EG's business, as well as the supportive regulatory framework. The third statement is curious, and is in sharp contrast to DBRS' opinion that for EG, operating in a *"stable regulatory framework"* and in an *"economically strong"* service area are strengths, and not weaknesses. In addition, it

[3] Included in Exhibit I.1.8-STAFF-14, Attachment 6.

seems to contradict S&P's second comment above regarding the benefits of operating in a *"supportive regulatory framework."* While, as a finance professional, I recognize the benefits of diversification; it is hard to understand why operating in one strong economic and regulatory environment could be worse than operating in numerous jurisdictions, where several of these would possess lower regulatory support and/or weaker economies. In short, and as above, I agree with DBRS' interpretation.

S&P went on to state (emphasis added) that *"The stable outlook on EGI reflects our expectation that it will continue to focus on, and* ***generate stable and predictable cash flows*** *from, its regulated gas distribution operations."* This was one assumption used in their *"base-case scenario."* S&P's other base-case scenario assumptions included:

• A **stable regulatory regime** in Ontario…

• EGI will **earn close to its authorized return on equity**

• EGI will operate at or close to its **authorized capital structure of 64%/36% debt** to equity for the duration of the outlook period

• The company **continues to pass through its natural gas costs and the federal carbon levy to its ratepayers**

So in other words, S&P (like DBRS) did not express concerns regarding EG's current allowed equity ratio of 36%, nor did it express concerns regarding carbon levies that could be passed through to its customers.

In its Business Risk assessment, S&P stated (emphasis added):

> *Our assessment of EGI's business risk* ***reflects our view of the OEB's regulatory framework, which underpins the utility's predictable and steady cash flow.*** *In our view, the OEB's regulatory process is* ***transparent, consistent, and predictable.*** *These factors collectively support the utility's timely recovery of prudently spent capital and operating expenses. In addition,* ***the federal carbon levy flows through to EGI's customers*** *and it recovers its gas commodity costs through a quarterly adjustment mechanism, which limits its exposure to commodity risk.*
>
> ***Further supporting our view is EGI's large customer base****. The company serves almost all of Ontario's gas distribution network with about 3.8 million customers, most of which are residential and small business customers. As*

> *such, **we expect EGI's cash flows to remain stable**. However, the demand for natural gas in the residential customer class can vary due to weather-driven fluctuations, which can lead to some cash flow volatility. Our favorable view of the company's business risk is **slightly offset** by its limited geographic footprint and exposure to a single regulatory regime.*

Reflecting this belief that EG's business risk profile was excellent, in its Financial Risk assessment, S&P stated (emphasis added):

> *We **assess EGI's financial measures using our low volatility financial benchmark table** rather than the benchmark we use for typical industrial issuers. This **reflects the company's lower-risk regulated gas distribution operations** and effective management of regulatory risk.*

In addition, S&P assessed EG's liquidity as adequate.

Finally, in its assessment of ESG risks, S&P rated all E, S and G factors as "2" (or neutral), where "1" is positive, "3" is moderately negative, "4" is negative, and "5" is extremely negative. Regarding ESG risks, S&P concluded (emphasis added): ***"ESG factors have no material influence on our credit rating analysis of EGI."*** Obviously, S&P, like DBRS, do not share the same concerns as Concentric regarding an increase in EG's risk profile due to the environmental factors that have been proposed by Concentric.

Both of these most recent debt rating reports provide similar messages regarding EG – it is a low-risk regulated operating utility operating in a strong economic environment with a supportive regulatory framework. In particular, EG possesses very low business risk and adequate financial risk, based on its existing capital structure, and after analyzing environmental factors that Concentric has proposed have contributed to a significant increase in EG's business risk profile, but which both rating agencies consider immaterial. In addition, the acquisition of UG is in the rear view mirror to some extent, and any potential negative uncertainties regarding that acquisition have turned out not to materialize, and in fact things have improved with respect to EG's risk profile, as noted in DBRS' 2022 report which refers to the synergies created by this acquisition as a positive factor for EG's risk profile.

3.2 The Cost of Debt for Enbridge

As of January 3, 2023 the yield on long-term A-rated Canadian utility bonds was 4.88% according to the yield on the Bloomberg A-rated utility yield index, while 30-year government of Canada bond yield was 3.22%. At that time, the following bid and ask yields were observed for Enbridge Gas Inc. bonds maturing at 09/2051 (also according to Bloomberg): Bid – 4.881%; Ask – 4.825%. This indicates that the market-determined yield on EG's long-term bonds was between 4.825% and 4.881%, and hence was less than or equal to the average Canadian A-rated utility yield. In other words, EG is able to attract debt capital at rates that correspond to those of similar risk entities. This provides support that given EG's current risk profile (including its existing allowed equity ratio) it is able to satisfy the third leg of the fair return standard. In other words, EG's risk profile will "*permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (**the capital attraction standard**).*"

3.3 A Quantitative Review of Enbridge Gas and Union Gas Performance

A compelling way of reviewing the performance of utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities – "where the rubber hits the road," so to speak. A review of the data provided in Attachment 1 of the response to IGUA-30 in Exhibit I.5.3 shows the following:

- EG earned ROEs that exceed the allowed ROE all 33 years over the 1990-2022 period.
- Union Gas (UG) earned ROEs that exceed the allowed ROE for 22 of 29 years over the 1990-2018 period, including 17 of the last 19 years during this period, and every year for the last 12 years (i.e., since 2006).

Table 1 provides the averages (and medians) of the earned ROEs, the allowed ROEs, and the difference between the earned ROEs and the allowed ROEs by EG and UG over the

1990-2021 and 1990-2018 periods respectively.[4] This table was created based on calculations in the working paper for Table 1, which is appended to my evidence as Attachment D, and which uses the data obtained from Attachment 1 of the response to IGUA-30 in Exhibit I.5.3. The annual average (and median) figures show the following:

- EG earned ROEs that exceed the allowed ROE by an average (median) of **1.09%** (1.10%) over the 1990-2022 period, and by 1.12% (1.14%) over the 1990-2018 period.
- UG earned ROEs that exceed the allowed ROE by an average (median) of **0.93%** (1.00%) over the 1990-2018 period.

This evidence shows that EG (and its predecessor companies) operates in a low risk environment that enables it to earn attractive returns – i.e., since it is consistently able to earn its allowed ROEs or higher. This can be considered the **strongest indication that EG possesses low total risk**.

[4] The last row in the summary statistics provided in Table 1 report a commonly used measure of volatility, the coefficient of variation (CV), which will be referenced in Section 4.2 when I compare them to those for the US Holding Company proxy sample. In this case, I use the CV of ROE – denoted as CV(ROE). The CV is determined by dividing the standard deviation (SD) of the ROE by the average ROE value. The rationale for using the CV as a measure of ROE volatility, rather than simply using the SD is that the SD is affected by the size of the average ROE. In other words, firms with larger ROEs would have higher SDs, even if they have less volatility, simply because the level of the ROE figures used to determine the SD are higher.

TABLE 1

	ENBRIDGE GAS		
(1990-2022)	**Actual ROEs**	**Allowed ROEs**	**Actual-Allowed**
Average	**11.03%**	**9.94%**	**1.09%**
Median	10.47%	9.51%	1.10%
Max	14.43%	13.25%	2.15%
Min	8.72%	8.34%	0.16%
StdDev	1.47%	1.47%	0.58%
CV(ROE)	**0.1331**	0.1476	
(1990-2018)	**Actual ROEs**	**Allowed ROEs**	**Actual-Allowed**
Average	**11.25%**	**10.12%**	**1.12%**
Median	10.77%	9.57%	1.14%
Max	14.43%	13.25%	2.15%
Min	9.42%	8.39%	0.16%
StdDev	1.41%	1.47%	0.59%
CV(ROE)	**0.1253**	0.1456	
	UNION GAS		
(1990-2018)	**Actual ROEs**	**Allowed ROEs**	**Actual-Allowed**
Average	**11.08%**	**10.15%**	**0.93%**
Median	10.75%	9.62%	1.00%
Max	15.30%	13.75%	4.81%
Min	8.03%	8.54%	-2.80%
StdDev	1.71%	1.70%	1.68%
CV(ROE)	**0.1546**	0.1674	

4. A Risk Comparison to Concentric's Proxy Groups

4.1 Business Risk

Section 3 shows that EG possesses very low business risk, which is seen as its number one strength by debt rating agencies. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments, and in fact my written evidence provided in the current Alberta GCOC Proceedings confirms this to be the case for Alberta operating utilities as well. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other industries that are non-regulated, that face greater demand variability, greater competition, and that do not have as great of an ability to flow through increases in their costs to their customers.

4.2 Comparing the Risk of EG to US Utilities

While EG has a debt rating of A from DBRS and an A- rating from S&P, Attachment 1 included in the response to IGUA54 of Exhibit I.5.3 shows that only four of the eight companies included in the US HoldCo proxy group have S&P debt ratings of A- or higher (i.e., Northwest at A+, and Atmos, ONE Gas and Spire all at A-). Three of the other four have lower ratings that range from BBB- (Southwest Gas), to BBB (South Jersey Industries), and to BBB+ (NiSource), while the fourth does not have an S&P rating. This suggests there may be potential issues regarding the comparability of this proxy group as being of "similar risk" to EG, which I explore further below.

The purpose of the analysis in this section is to provide quantitative evidence comparing the risk of US utilities that are included in Concentric's US OpCO and US HoldCo proxy groups to that of EG. In particular, the evidence provided by Concentric relies heavily on two US proxy groups based on the premise that such samples are of comparable risk to EG, and therefore implies there is no need to make adjustments for comparison purposes. While US utilities may not be high business risk firms relative to US firms in other industries, they clearly have more risk than EG. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa.

One effective way to compare overall riskiness of EG to its proposed US counterparts would be to compare their ability to earn their allowed ROEs, as I did for EG (and UG) in Table 1. Recall that EG earned ROEs above the allowed ROEs for 33 straight years from 1990 to 2022, and that over the entire period it earned ROEs that exceeded allowed ROEs by an annual average (median) of **1.09%** (1.10%). This is **bottom line empirical evidence** that EG has low risk.

Concentric did not provide evidence regarding earned versus allowed ROEs for the utilities it included in its four proxy groups in response to IGUA-50(b) as had been requested. And unfortunately, it is not practical within the budget available for me to undertake a comprehensive comparison of the earned ROEs to allowed ROEs for the US utilities included in Concentric's proxy groups. I would also note that the eight US utilities included in Concentric's US Hold Co group are holding companies that own several distinct operating utilities, which operate in numerous jurisdictions. Fortunately, I can point to two other sources that did conduct such analyses of broader samples of US utilities, both of which provide strong evidence that, unlike EG (and UG), **the average U.S. utility earns well below their allowed ROE!**

For example, a recent Oliver Wyman report on North American utilities suggested that the "average utility **does not earn its allowed return on equity**."[5] Even stronger support for this conclusion can be found in an empirical study by Azgad-Tromer and Talley (2017). This study examined allowed ROEs versus actual ROEs using observations from all 50 states as well as four Canadian provinces over the 2005-2016 period.[6] The study contained predominantly U.S. observations, with only 18 of the 544 observations being from Canada. Hence their finding that "awarded ROEs appear to overshoot realized ROEs by between 1.5 and 1.75 percent…" can be seen as a strong indication that U.S. utilities do not on average earn their awarded ROE. In fact, it seems they significantly fall short of doing so, with average (median) **under-performance of 1.79% (1.45%)** according to Figure 4 of their study. This contrasts significantly with the evidence for EG provided in Table 1, which showed that EG earned well above (i.e., approximately **1.1%** on average) their awarded ROEs over the 1990-2022 period, and **never earned below it** – not even in one out of 33 years. Clearly, it is inappropriate to compare the two groups of utility firms, which amounts to comparing apples to oranges.

Aside from referencing these sources of evidence regarding US utilities' inability to earn their awarded ROE, another effective way of comparing the riskiness of EG to that of the US utility proxy groups is to compare the volatility in earned ROEs. ROE volatility is a measure of total risk (i.e., business and financial risk), since business risk influences operating income volatility while financial leverage influences net income volatility. I will use the coefficient of variation of the earned ROEs (i.e., CV(ROE)), described in footnote 4 as my

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[5] Source: Page 10 of "North America Utilities: Still a Smart Bet for the New Grid," Oliver Wyman, 2015. Appended to my evidence as Exhibit BK.

[6] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://www.semanticscholar.org/paper/The-Utility-of-Finance-Azgad-Tromer-Talley/c5913d92dc6600974956b13c9383bee6f61b731b).

ROE volatility measure, and will compare the CV(ROE) for the US HoldCo sample over the 2013-22 period[7] to the ones calculated for EG (and UG), which were reported in Table 1.[8]

Table 2 provides the summary statistics for earned ROEs for the US HoldCo sample over the 2013-2022 period, similar to those provided for EG and UG in Table 1 over the 1990-2022 and 1990-2018 periods. Table 2 shows that the reported ROEs for the US utilities averaged 8.41% over the 2013-22 period, with a median of 9.25%. While not reported in Table 1, the 2013-22 average (median) reported ROE for EG was 9.89% (10.05%), while the 2013-2018 average (median) reported ROE for UG was 9.89% (9.77%). If we look at the last column in Table 2 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the US sample to the results reported in Table 1 for EG and UG, we can see that the US utilities displayed much greater volatility in ROEs than both EG and UG. In particular, the average CV(ROE) across all of the US utilities over the 2013-22 period was **0.446**, which is **more than three times larger** than the 1990-2022 average for EG of 0.133, and the 1990-2018 average for UG of 0.155 that are reported in Table 1. While not reported in Table 1, if we look at the same time period used for constructing the US HoldCo results, we find that the 2013-2022 average CV(ROE) for EG was much lower at **0.069**, while the 2013-2018 average for UG was also much lower at **0.069** – both being **less than one-sixth the US average**. The working papers for Table 2 are appended to my evidence as Attachment E.

[7] Data was only available for most companies as far back as 2013, so I could not find reliable data for previous years.
[8] I was forced to focus solely on Concentric's US HoldCo sample since this data is accessible with a reasonable level of effort, whereas the ROE earned data for companies in the US OpCo would be extremely time consuming to locate. Further, and as mentioned by Concentric in its response to IGUA-50(b) "calculating earned ROEs from accounting data is complicated by the many common adjustments made for regulatory accounting purposes."

TABLE 2

SUMMARY STATISTICS – US REPORTED ROEs (2013-2022)

Utility	Average	Median	Max	Min	StDev	CV(ROE)
Atmos Energy Corp	10.29%	9.93%	13.90%	8.94%	1.42%	0.138
New Jersey Resources Corp	13.20%	12.54%	17.58%	6.78%	3.41%	0.258
NiSource Inc.	6.24%	7.48%	13.11%	-1.46%	4.86%	0.780
Northwest Natural Holding Company	6.48%	7.94%	8.75%	-6.98%	4.77%	0.736
ONE Gas Inc	8.26%	8.54%	9.01%	6.55%	0.87%	0.105
South Jersey Industries Inc.	7.15%	10.18%	11.03%	-0.32%	4.34%	0.607
Southwest Gas Corporation	7.71%	8.98%	11.15%	-6.76%	5.20%	0.674
Spire Inc	7.94%	8.42%	10.82%	3.22%	2.14%	0.270
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**8.41%**	9.25%	11.92%	1.25%	3.38%	**0.446**
Median	7.82%	8.76%	11.09%	1.45%	3.87%	0.438
Max	13.20%	12.54%	17.58%	8.94%	5.20%	0.780
Min	6.24%	7.48%	8.75%	-6.98%	0.87%	0.105
StDev	2.31%	1.62%	2.89%	6.13%	1.69%	0.280

Date Source: www.morningstar.ca

The ROE analysis above shows clearly that the utilities included in the US HoldCo sample possess greater risk than EG. This is hardly surprising given that this sample is comprised of holding companies with various ownership structures and a variety of exposures to risks to which EG is not exposed – at least not to the same extent.

4.3 Comparing the Risk of EG to Canadian Holding Company Utilities

While EG has a debt rating of A from DBRS and an A- rating from S&P, Attachment 1 included in the response to IGUA-54 of Exhibit I.5.3 shows that only two of the six companies included in Concentric's Canadian HoldCo proxy group have S&P debt ratings of A- (i.e., Fortis Inc. and Hydro One Ltd.), while the other four have lower ratings that range from BBB- (AltaGas), to BBB (Algonquin and Emera), and to BBB+ (Canadian Utilities). This points to issues regarding the comparability of this proxy group as being of "similar risk" to EG.

The lower debt ratings could be the result of a number of factors. For example, as confirmed by Concentric in response to IGUA-60 of Exhibit I.5.3, with respect to the six companies included in the Canadian HoldCo proxy group:

- Four of the five operating companies referenced for Algonquin are US-based, with only one Canadian company.
- All five of the AltaGas Inc. operating companies referenced are US-based.
- The only company referenced for CU Ltd. is ATCO Gas, which is Canadian-based (Alberta).
- Both of the two operating companies referenced for Emera are US-based.
- Two of the three operating companies referenced for Fortis are US-based, with FortisBC Energy being the lone Canadian company referenced.
- The only operating company referenced for Hydro One is Canadian-based.

Reviewing Attachment 1 included in the response to IGUA-55 of Exhibit I.5.3, we can see that of the 18 operating companies referenced by Concentric for the Canadian HoldCo group, 15 of them operate across 13 US jurisdictions, while just three operate in three Canadian jurisdictions. In other words, this sample includes a heavy weighting in terms of US operating companies, which no doubt influences their debt ratings.

In addition to examining debt ratings, another way to compare the riskiness of EG to that of Concentric's Canadian HoldCo proxy group is to compare the volatility in earned ROEs, similar to what was done above for the US HoldCo group. Table 3 shows that the reported ROEs for the Canadian HoldCo sample companies averaged 8.19% over the 2013-22 period, with a median of 8.03%, below the 2013-22 average (median) reported ROE for EG of 9.89% (10.05%), and the 2013-2018 average (median) reported ROE for UG of 9.89% (9.77%). The last column in Table 3 shows that the average CV(ROE) for the Canadian OpCo sample over the 2013-22 period was **0.630**, which is **much, much larger** than the 1990-2022 average for EG of 0.133, and the 1990-2018 average for UG of 0.155, and even more so relative to the 2013-2022 average CV(ROE) for EG of **0.069**, and the 2013-2018 average for UG of **0.069.** The working papers for Table 3 are appended to my evidence as Attachment E (the same Attachment as the Table 2 working papers).

TABLE 3

SUMMARY STATISTICS – CANADIAN HOLDCO REPORTED ROEs (2013-2022)

2013-2022	**Average**	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Algonquin Power	8.18%	6.53%	17.77%	1.76%	5.15%	0.630
AltaGas Inc.	3.97%	4.24%	13.21%	-11.15%	6.60%	1.664
Canadian Utilities Ltd.	10.88%	11.22%	17.43%	6.43%	3.79%	0.349
Emera Inc.	9.79%	10.24%	17.00%	4.30%	3.94%	0.402
Fortis Inc.	7.57%	7.25%	10.40%	5.45%	1.57%	0.208
Hydro One Ltd.	8.77%	8.71%	17.78%	-0.94%	4.62%	0.527
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**8.19%**	8.03%	15.60%	0.98%	4.28%	**0.630**
Median	8.47%	7.98%	17.22%	3.03%	4.28%	0.464
Max	10.88%	11.22%	17.78%	6.43%	6.60%	1.664
Min	3.97%	4.24%	10.40%	-11.15%	1.57%	0.208
StDev	2.38%	2.56%	3.08%	6.51%	1.67%	0.527

Date Source: www.morningstar.ca

The ROE analysis above shows clearly that the utilities included in the Canadian HoldCo sample possess greater risk than EG, which supports the lower debt ratings for four of the six companies included in this sample. This is hardly surprising given that this sample is comprised of holding companies that have overall exposure to a large number of US operating companies, unlike EG, which is an Ontario-based operating company. As such, these holding companies are subject to a variety of exposures to risks to which EG is not – at least not to the same extent. In short, this proxy group is not a very good comparator group for EG for the stated purpose of Concentric's analysis.

4.4 Concentric's Canadian OpCo Proxy Group

Given that none of Concentric's three proxy groups discussed above provide reasonable "similar risk" comparables, I now examine Concentric's fourth group – the Canadian OpCo proxy group. This group consists of 10 Canadian Gas operating utilities across Canada, which seems like a promising start. Unfortunately, upon closer examination, it is clear that seven of the utilities included in this sample are not "similar risk" comparables due to their extremely small size relative to EG.

Before even beginning my formal analysis, I would note that it is clearly inappropriate to include three Pacific Northern Gas Ltd companies and hence provide a 30% sample weighting to this small utility, which operates in adjacent geographic regions that entail much greater risk than Ontario. In order to examine all 10 utilities in this sample, I begin by gathering the debt ratings (where available) and the 2021 (or 2019) revenue figures for all 10 of these companies, which are reported in Table 4.

TABLE 4

CANADIAN OPCO PROXY GROUP

Utility	Debt Rating(s)	2021 or 2019[9] Revenue ($m CAD)	Equity Ratios[10] (%)
Apex Utilities Inc.	DBRS(Morningstar): BBB(High) Stable (Dec. 2022)	139[11]	39.0
ATCO Gas	N/A CU Inc: DBRS(Morningstar): A(High) Stable (Aug. 2022) S&P: A- Stable (Aug. 2022)	1,171[12]	37.0
Energir (formerly Gaz Metro)	DBRS(Morningstar): A Stable (April 2022)[13] S&P: A (Dec. 2022)[14]	1.324[15]	38.5
FortisBC Energy	DBRS(Morningstar): A Stable[16] Moody's: A3 (Dec. 2022)[17]	1,714[18]	38.5
Gazifere Inc.	No ratings could be found.	228.4 (2019)[19]	40.0
Heritage Gas Limited (now Eastwood Energy)	In response to an undertaking filed April 6, 2023 (EB-2022-0200, Exhibit JT7.24, Attachment 1), Concentric indicated that TriSummit Utilities Inc. issues debt for Heritage Gas and is rated BBB by DBRS.	121.3 (2019)[20]	45.0
Liberty Utilities Gas New Brunswick	DBRS(Morningstar): BBB Stable (Feb. 2022)[21]	49.3 (2019)[22]	45.0
Pacific Northern Gas Ltd	In response to an undertaking filed April 6, 2023 (EB-2022-0200, Exhibit JT7.24, Attachment 1), Concentric indicated that TriSummit Utilities Inc. issues debt for Pacific Northern Gas and is rated BBB by DBRS.	264.21 (2019)[23]	46.5
Pacific Northern Gas Ltd (Fort St. John/Dawson Creek)	In response to an undertaking filed April 6, 2023 (EB-2022-0200, Exhibit JT7.24, Attachment 1), Concentric indicated that TriSummit Utilities Inc. issues debt for Pacific Northern Gas and is rated BBB by DBRS.	Would be included in the revenue figure for Pacific Northern Gas Ltd.	41.0
Pacific Northern Gas Ltd (Tumbler Ridge)	In response to an undertaking filed April 6, 2023 (EB-2022-0200, Exhibit JT7.24, Attachment 1), Concentric indicated that TriSummit Utilities Inc. issues debt for Pacific Northern Gas and is rated BBB by DBRS.	Would be included in the revenue figure for Pacific Northern Gas Ltd.	46.5

[9] I was unable to locate the 2021 revenue figures for the last 6 companies in this proxy group, likely due to their small size, but I was able to find the 2019 figures, which should be close enough to the 2021 figures to provide reasonable perspective as to their relative size.
[10] As reported in Schedule 4 on page 154 of Concentric's evidence.
[11] Source: Attachment F (page 3).
[12] Source: Attachment G (pdf page 165).
[13] Source: https://www.dbrsmorningstar.com/research/396638/energir-lp-rating-report, March 29, 2023.

Table 3 shows that Gazifere does not appear to have public debt ratings, which means it does not issue public debt (i.e., bonds or debentures), while Heritage Gas, the three Pacific Northern Gas companies and Apex, all have debt issued by TRiSummit Utilities Inc., which has a BBB rating, well below EG's DBRS rating of A. On this basis, alone, they do not make very good comparators (i.e., similar risk) to EG. Further review of Table 3 makes it obvious that EG, which reported $37.558b in 2021 revenue, is dramatically larger than all of the 10 Canadian OpCos in this proxy group. In fact, the reported revenue figures for Apex (2021) plus the last six utilities listed in the table (2019) are all well below 1% of EG's 2021 revenue. The largest revenue reported by any of these seven utilities is the $264.21 million figure reported by Pacific Northern Gas Ltd in 2019 (which actually comprises the sum of the last three companies included in Concentric's sample) which is a mere 0.70% of EG's 2021 revenue!

Comparing the awarded equity ratios of these extremely small utilities to those of EG, and assigning them equal weighting in calculated averages for the proxy group, is clearly inappropriate, as they would likely be awarded higher equity ratios based heavily on the risks associated with their small size.

Mr. Coyne of Concentric appears to agree with this assertion as noted in his 2021 evidence submitted before the New Brunswick Energy and Utilities Board, where he made the following statements,[24] which makes it curious as to why Concentric would include seven very small utilities in this proxy group, and advance them as "similar risk" utilities to EG (emphasis added):

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[14] Source: https://www.google.com/search?client=firefox-b-d&q=Energir+S%26P+debt+rating , March 29, 2022.
[15] Source: Attachment H (page 22).
[16] Source: Attachment I (page 46).
[17] Source: Attachment J (page 2).
[18] Source: Attachment K (page 7).
[19] Source: Attachment C, "James Coyne Testimony on behalf of Liberty Utilities (Gas New Brunswick) ZP, March 31, 2021, Figure 31, page 70.
[20] Ibid.
[21] Source: https://www.dbrsmorningstar.com/research/392955/dbrs-morningstar-confirms-liberty-utilities-canada-lp-at-bbb-stable-trends, March 29, 2023.
[22] Source: Attachment C "James Coyne Testimony on behalf of Liberty Utilities (Gas New Brunswick) ZP, March 31, 2021, Figure 31, page 70.
[23] Ibid.
[24] Source: Attachment C, "James Coyne Testimony on behalf of Liberty Utilities (Gas New Brunswick) ZP, March 31, 2021, Figure 31, pages 60-63.

> *Liberty is substantially smaller than the vast majority of other gas distribution utilities in Canada and the U.S. The **small size** of Liberty relative to the proxy group companies **is an important risk factor** in determining Liberty's cost of equity*. (page 60, lines 20-22)
>
> *Liberty's small size relative to the proxy group companies means that Liberty's **earnings and cash flows may be disproportionately affected by events** such as the loss of its larger customers, **weaker than expected demand** for gas distribution service **due to general macroeconomic conditions** in the service territory, **or fuel price volatility**.* (page 62, lines 4-7)
>
> *My conclusion is that Liberty is significantly smaller than the proxy group companies and that **investors would require a substantial risk premium** in relationship to the larger and more diversified proxy group companies.* (page 63, lines 27-29)

Eliminating these seven utilities leaves three reasonable utilities in this proxy group, even though they are all still much smaller than EG, with 2021 revenue figures of $1.171b for ATCO Gas (3.1% of EG's revenue), $1.324b for Energir (3.5% of EG's revenue), and $1.714b for FortisBC Energy (4.6% of EG's revenue). So while these companies are all less than 1/20th of the size of EG, and hence "would require a substantial risk premium," according to Mr. Coyne's 2021 evidence quoted above, they are the most reasonable at some level.

Figure 35 on page 102 of Concentric's evidence reports the average equity ratio for this proxy group at 40.5%; however, if we eliminate the seven abnormally small utilities the average falls to 38.0%; recognizing that these three comparators are still less than 1/20th the size of EG and would warrant higher equity ratios to compensate for this small size risk, and are not truly "similar risk" utilities to EG. This implies that if Concentric had properly conducted this awarded equity ratio analysis, they would have concluded that the awarded equity ratios of "similar risk" utilities was no greater than **38.0%**, and not the estimates in the 40-45% range it arrives at; although I do not advocate this approach.

4.5 Conclusions About EG's Risk Versus Concentric's Four Proxy Groups

The discussion in Section 3 confirms the low risk nature of EG. In fact, the most important conclusion that arises from the analysis in Section 3 and in Sections 4.1-4.3 is that EG possesses very low risk – much lower than the utilities included in at least three of Concentric's proxy groups. My quantitative analysis in Sections 4.2 and 4.3 confirms this fact, which is consistent with the long-standing low business risk assessment of EG by debt rating agencies.

The discussion in Sections 4.1 to 4.3 confirms that the US and Canadian holding company proxy groups are poor comparators to EG, since they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the US and other non-Canadian jurisdictions (which also applies to Concentric's US OpCo proxy group), and partly due to the nature of their operations which entail more risk. These conclusions with respect to holding companies are consistent with Concentric's own observation that regulated operating company samples are the "most applicable;" although Concentric does not explain specifically how it adjusts for this fact. Given the significant issues with using US comparables, I recommend giving extremely low weighting to the evidence advanced by Concentric that relies upon US utility statistics, and also the evidence that relies on the Canadian HoldCo group given the significant proportion of US operations of this group, as discussed in Section 4.3.

The only potentially valid (i.e., similar risk) proxy group used by Concentric is the Canadian OpCo group; although, seven of the 10 companies included in that sample are not legitimate comparators due to their extremely small size (i.e., much lower than 1% of the size of EG), while the remaining three are also less than 5% of the size of EG, which should be adjusted for in interpreting related statistics due to the "small size impact," as also noted by Mr. Coyne of Concentric in his 2021 evidence provided for the New Brunswick Energy and Utilities Board. Figure 35 on page 102 of Concentric's evidence reports the average equity ratio for the Canadian OpCo proxy group at 40.5%; however, if we eliminate the seven abnormally small utilities the average falls to **38.0%**; recognizing that these three comparators are still less than 1/20th the size of EG and would warrant higher equity ratios to compensate for this small size risk, and so are not truly "similar risk" utilities to EG.

As discussed previously, I do not advocate blindly looking at the averages (or medians) of authorized equity ratios in other jurisdictions to determine the appropriate equity ratio for EG, since this approach does not take into account current market conditions, or those that existed on the record of such proceedings. Further, Concentric's approach is additionally confounded by the fact that three of its proxy groups are not of "similar risk" to EG, while the fourth group includes seven utilities that are also not comparable, with the remaining three utilities requiring adjustments to compensate for their small size relative to EG. In short, the entire approach of pointing "relatively" to the average awarded equity ratios of other utilities, all of which are not of comparable risk, is flawed by design. The appropriate approach is to determine the appropriate equity ratio for EG on an "absolute basis," with respect to its business and financial risk profiles.

5. FINANCIAL RISK AND CREDIT METRICS

5.1 Enbridge Gas Inc. – Credit Metric Analysis

While Concentric did not provide proforma credit metrics for EG over the 2022-24 test period in its initial evidence, in response to IGUA-44a of Exhibit I.5.3, it did provide a pdf attachment (albeit not the requested working papers and underlying data) that included the forecasts for four of the five metrics it reported in Figure 37 of its evidence, as well as data points that allowed me to estimate the fifth metric (EBITDA to interest). This information is presented in Table 5.

TABLE 5

ENBRIDGE GAS CREDIT METRICS (2019-2024)

	EBITDA Coverage*	**FFO/Int Coverage**	**FFO/Debt**	**Debt/EBITDA**
2024 (38% ER)	4.73	4.44	14.49	5.03
2024 (36% ER)	4.50	4.25	13.76	5.24
2023	4.17	4.05	12.75	5.74
2022	4.07	3.98	12.47	5.88
2021	4.03[25]	3.92	12.19	5.94
2020	3.83	3.73	12.03	5.93
2019	4.13	3.97	13.05	5.51

* The EBITDA Coverage ratios were not provided by Concentric in the response to IGUA-44a, so I calculated these figures as EBITDA/Interest, using the adjusted EBITDA and Interest expense figures provided in that Attachment.

The forecast metrics provided in Table 5, which are all based on the existing equity ratio of 36% (except for the first row, which shows the 2024 forecast metrics based on a 38% equity ratio), show clearly that EG's metrics can be expected to improve, and in fact will exceed the metric estimates used by S&P in determining its stable assessment for EG's rating (as discussed in Section 5.2). This analysis clearly demonstrates that at a 36% equity level, the credit metrics threshold are more than adequate.

5.2 Debt Rating Reports' Comments Regarding EG's Financial Risk

As discussed in Section 3.1, EG's DBRS debt rating report of September 27, 2022 confirmed its rating of **A and stable**. With respect to financial risk, DBRS provided the following comments regarding EG's financial profile (emphasis added):

[25] Concentric reported EBITDA coverage of 2.36 (Reg only) and 4.29 (S&P) for EG in 2021 in Figure 37 of its evidence. It is not clear where the 2.36 came from, as Concentric did not include EBITDA Coverage figures in the Attachment in response to IGUA-44a, nor did it provide the workpapers underlying such calculations as requested in IGUA-44a. So it is impossible to discern how Concentric arrived at this estimate without additional information. However, using other data provided by Concentric in the "pdf response" in the Attachment to IGUA-44a, the EBITDA coverage ratio for 2021 is calculated as: EBITDA/Interest = 1,531.2/379.9 = 4.03, which is much more in line with the EBITDA coverage ratio reported by S&P of 4.29, as well as the other calculated EBITDA coverage ratios provided in the table above, also calculated using data provided by Concentric in the pdf response to IGUA 44a. The 2021 figures reported in Concentric's Figure 37 for FFO Interest Coverage and Debt to EBITDA are also slightly off those included in the response to IGUA-44a, but not by very much – i.e., 3.93 and 5.92 in Figure 37 versus 3.92 and 5.94 in the response to IGUA-44a.

FINANCIAL PROFILE:

Summary

• ***All credit metrics remained solid*** *in the last twelve months (LTM) ended June 30, 2022,* ***reflecting relatively stable cash flow and reasonable debt leverage.***

• *The* ***debt-to-capital ratio, excluding goodwill, has remained relatively stable since the amalgamation*** *and has stayed at the low end of DBRS Morningstar's "A" rating range. This capital structure level is* ***consistent with the regulatory capital structure of 36% equity/64% debt.***

• *The* ***cash flow-to-debt ratio*** *for the LTM ended June 30, 2022,* ***improved modestly*** *from 2021 because of higher cash flow for H1 2022 compared with H1 2021.*

• ***EBIT-interest coverage*** *for the LTM ended June 30, 2022,* ***continued to benefit from solid operating income*** *for the period.*

• *EGI has generated substantial free cash flow deficits for the last couple of years as a result of a large capex program in 2020 and 2021 (averaging $1.35 billion each year). Most of growth capex was spent on growth capital projects that were approved by the regulator (see below).*

• *DBRS Morningstar notes the dividend/cash flow ratio has increased since 2018. This increase combined with large growth projects caused EGI to require substantial external funds to finance its cash flow deficits.*

• *However, EGI's financing plan has been to maintain the debt-to-capital ratio* ***in line with the regulatory capital structure of 64% debt/36% equity****.*

The DBRS report noted the maintenance of *"solid credit metrics"* and expressed no concerns regarding the existing 36% equity ratio, which it incorporated into its "stable" outlook for EG's debt rating of A. In short, there is nothing in its financial risk analysis, or its business risk assessment (excellent) discussed in Section 3.1 to indicate DBRS is uncomfortable with EG's existing equity ratio of 36%. This supports my analysis in Section 5.1, which indicates there is no need for an increase in EG's equity ratio.

As also noted in Section 3.1, EG's S&P debt rating report of July 21, 2022 confirmed EG's rating at **A- and stable**. In this report, S&P noted several financial factors in its Outlook, as quoted below (emphasis added):

> ***Outlook:***
>
> *The stable outlook on EGI reflects our expectations that it will* ***continue to focus on, and generate stable and predictable cash flows*** *from, its regulated gas distribution operations. We also expect that the company will continue to benefit from modest growth in its new customers and the timely and on-budget completion of its capital programs. This leads us to* ***forecast FFO to debt of 11%-12% during our two-year outlook*** *period.*[26]
>
> *The stable outlook also reflects our view that* ***Enbridge Inc.*** *(Enbridge), the company's parent, will improve its S&P Global Ratings adjusted credit metrics throughout the forecast period, with its debt to EBITDA decreasing to 4.7x and its FFO to debt increasing to about 16% by 2024.*
>
> *Furthermore, the stable outlook reflects our expectation that both the utility's insulation features and Enbridge's strategy to preserve its credit strength will not change.*
>
> ***Downside scenario***
>
> *We* ***could*** *lower our ratings on EGI if its financial measures deteriorate,* ***including FFO to debt approaching 10% with no prospects for improvement.***[27]
>
> *Alternatively, we could lower our ratings on EGI if we lower our ratings on Enbridge. This could occur if Enbridge's consolidated S&P Global Ratings-adjusted FFO to debt falls below 13% or it sustains debt to EBITDA of more than 5x.*

[26] In fact, Concentric's calculations provided in response to IGUA-44a (as replicated in Table 5 above) show that this ratio can be expected to rise to 12.47% in 2022, 12.75% in 2023, and 13.76% in 2024 (all based on a 36% equity ratio).

[27] This scenario seems unlikely according to the forecast FFO to debt ratios of 12.47%, 12.75% and 13.76% for 2022-24 that are estimated by Concentric, as discussed in footnote 26, all of which are based on a 36% equity ratio.

> ***Upside scenario***
> *Although unlikely, we could upgrade the company over the next 18-24 months if we also upgrade Enbridge and raise our stand-alone credit profile (SACP) on EGI.*
> *We believe the company could warrant a higher SACP if it improves its financial measures,* ***including FFO to debt of consistently above 13%.***[28] *An upgrade at the parent level would require Enbridge to maintain FFO to debt of more than 17% and S&P Global Ratings adjusted debt to EBITDA of about 4x while sustaining its asset mix and cash flow stability.*

In that same report, S&P described its base-case scenario as quoted below (emphasis added):

> ***Our Base-Case Scenario***
> ***Assumptions***
> *•* ***Stable and predictable cash flows*** *from its regulated gas distribution operations, as well as modest new customer growth;*
> *• A* ***stable regulatory regime*** *in Ontario with no material adverse regulatory decisions;*
> *• EGI will primarily operate under inflation-indexed rates throughout 2022 and 2023 before starting a new rate application cycle in 2024;*
> *• Annual revenue increases through 2023 will be subject to a productivity stretch factor constraint of 0.3%, which reduces the annual revenue rise by the equivalent amount;*
> *• All earnings exceeding 150 basis points over the OEB's approved return on equity will be shared equally between EGI and its ratepayers;*
> *•* ***EGI will earn close to its authorized return on equity****;*
> ***• EGI will operate at or close to its authorized capital structure of 64%/36% debt to equity for the duration of the outlook period;***

[28] This scenario is much more likely than the downside scenario, according to the forecast FFO to debt ratios reported in Table 5, which are forecast to hit 12.75% in 2023, and 13.76% in 2024 (based on a 36% equity ratio).

• *The company* ***continues to pass through its natural gas costs and the federal carbon levy to its ratepayers****;*

• *Annual capital expenditure of about C$1.4 billion-C$1.6 billion between 2022 and 2024; and*

• *Annual dividends of about C$200 million in 2022, 2023, and 2024.*

Key metrics

Enbridge Gas Inc. --Key Metrics*

	2021a	***2022e***	***2023f***
FFO to debt (%)	*12.4*	*11-12*	*11-12*
FFO cash interest coverage (x)	*4.3*	*4.0-4.5*	*4.0-4.5*
Debt to EBITDA (x)	*6.2*	*6.0-6.5*	*6.0-6.5*

**All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.*

The S&P report, like the DBRS report, expressed no concerns regarding the existing 36% equity ratio, which it also incorporated into its “stable” outlook for EG’s rating. In fact, their stable assessment was based upon forecast 2022-23 metrics that are worse than those estimated by Concentric as reported in Table 5 above. In particular, the 2022 and 2023 FFO to Debt ratio forecasts of 11.0-12.0 for both years that were relied upon by S&P in its stable assessment are below the 2022 and 2023 forecasts of 12.47 and 12.75 reported in Table 5; while the S&P forecasts for Debt to EBITDA of 6.0-6.5 for both years that they also relied upon are higher than the 2022 and 2023 forecasts of 5.88 and 5.74 reported in Table 5; and, the S&P forecasts for FFO cash interest coverage for 2022 and 2023 of 4.0-4.5 are in line with the corresponding forecast values of 3.98 and 4.05 reported in Table 5.

5.3 Conclusions Regarding EG’s Financial Risk and Credit Metrics

Section 5.1 shows that the metrics for EG are forecast to improve over the test period, and in fact will exceed the metric estimates used by S&P in determining its stable assessment for EG’s rating (as discussed in Section 5.2), which shows that at a 36% equity level, the credit metrics threshold are **more than adequate**. Section 5.2 shows there is nothing in either DBRS’ or S&P’s financial risk analysis, or their previously discussed business risk assessments (excellent), to indicate that either rating agency is uncomfortable with EG’s existing equity ratio of 36%. In short, there is clearly no need for an increase in EG's equity ratio to maintain its current strong credit ratings (financial integrity), or its ability to continue to access capital at favorable rates.

6. Other Issues with Concentric's Evidence

6.1 Remaining Book Value of Asset Lives and Risk

On pages 91-92 of its evidence Concentric asserts that:

> *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.*

Exhibit I.5.3-IGUA-56(a) asked the following:

> *a) Can Concentric provide empirical support for the cited statement? For example, is there empirical evidence showing that the required rate of return on equity for companies with longer-lived assets is higher than for those with shorter-lived assets?*

The response was:

> *Concentric refers to the risk of return of capital which is placed at greater risk with long-lived assets.*

So essentially, Concentric provided **no support** for this assertion.

Exhibit I.5.3-IGUA-56(b) asked the following:

> *b) Is Concentric suggesting that investors would prefer to invest in companies whose assets are older and nearer the end of their useful lives? If so, please explain the logic behind this assertion. If not, please explain why this is not a corollary of the suggestion that investing in companies with newer and less depreciated assets is riskier than investing in companies with older and more depreciated assets.*

The response was:

> *Under circumstances with shifting public policy that calls into question the growth and sustainability of the natural gas industry, investors would*

> *naturally seek to mitigate exposure to the industry. 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.*

Essentially Concentric provided no meaningful response to the core of this question, which is why would investors prefer to invest in gas utilities with older assets rather than those with newer assets (like EG), even if there were significant immediate concerns over transition risk (which Concentric has failed to demonstrate actually exist)?

Exhibit I.5.3-IGUA-56(c) asked the following:

> *c) Would having assets that are newer actually reduce risk for companies? For example, wouldn't this imply the company would have to allocate relatively less to future capital expenditures to upgrade assets than would comparable companies with older assets?*

The response was:

> *The balance of newer vs. older assets involves more than investment risk. Gas utilities must maintain the safety and reliability of their systems, even if risks of long term asset recovery are increasing. Unlike some industries where investors can allow assets to deteriorate under unfavorable market conditions, utilities are required to maintain their systems to a high level of safety and reliability.*

The first sentence in Concentric's response to this question suggests that asset lives involves *"more"* than investment risk, despite asserting in the quote above from pages 91-92 that it does affect investment risk (i.e., the quote refers to *"investors"* and *"invested capital"*). The remainder of the response in fact confirms that it is important to be invested in newer assets, particularly for utility companies. So, in fact the response indicates that investors would prefer utilities with newer assets, all else being equal – which is clearly obvious to investors and other capital providers.

6.2 EG's Lack of Regulatory and Geographic Diversity

On page 99 of its evidence Concentric asserts that (emphasis added):

> *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.*

Exhibit I.5.3-IGUA-59(a) asked the following:

> *a) Concentric has stated previously that the operating company proxy groups are the "most applicable" to Enbridge Gas. Therefore, if we first look at these two most applicable proxy groups, please confirm that this statement would also apply to the 10 operating companies included in the Canadian Operating Company Proxy Group, as well as to the 10 companies included in the US Operating Company Proxy Group. I.e., they also operate in one jurisdiction and geographic region as well. If not please explain.*

In its response, Concentric confirmed this statement. So in fact, this statement applies to 20 of the 34 utilities included in Concentric's four proxy groups, and all 20 of the utilities in its two operating company samples, which it states are the "most applicable" to EG. Therefore, it is difficult to understand why Concentric believes this is a significant risk factor for EG relative to its proxy groups, the 20 most applicable members of which face the identical situation; albeit many in weaker economies and/or with weaker regulatory support.

Exhibit I.5.3-IGUA-59(b) asked the following:

> *b) Turning attention to the two (less applicable) holding company proxy groups, please confirm that jurisdiction exposure for the two holding company proxy groups range from (average): one jurisdiction (for two companies) to five, with an average of 3.2 for the six Canadian holding companies; and, one jurisdiction to eight, with an average of 3.4 for the eight US holding companies. If not confirmed please provide the range and average for these two proxy groups.*

In its response, Concentric confirmed this statement. So in fact, this statement suggests that the diversification benefits to its holding company samples, which samples are *"less applicable"* in any event, are minimal, with diversification averages of only 3.2 and 3.4

jurisdictions. As above, it is difficult to understand why Concentric believes that a single (albeit large and economically strong) jurisdiction is a significant risk factor for EG.

Exhibit I.5.3-IGUA-59(c) asked the following:

> *c) Given that the 20 companies included in the two most applicable groups (i.e., operating companies) have no additional regulatory or regional diversity; and (b) there is very little additional diversity, please justify the statement: "This lack of regulatory and geographic diversity partially mitigates the risk reductions created by the Company's large size."*

The response was:

> *The statement on Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 99 of 164 that "[t]his lack of regulatory and geographic diversity partially mitigates the risk reductions created by the Company's large size" is supported by the following statement made by S&P that is quoted on page 99 "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."*
>
> *Concentric agrees that the other gas operating utilities in Canada and the U.S. also operate in single jurisdictions. However, Figures 23 and 24 of Concentric's Report demonstrate that those other gas operating utilities have mean and median allowed equity ratios from 40.5% in Canada to 51.4% in the U.S., as compared to Enbridge Gas at 36% deemed equity.*

Essentially Concentric provided no meaningful response to the core of this question. The first paragraph simply says that "because S&P said so," which S&P statement I disagree with. As noted in Section 3.1 of my evidence S&P's statement is in sharp contrast to DBRS' opinion that for EG, operating in a *"stable regulatory framework"* and in an *"economically strong"* service area are strengths, and not weaknesses. In addition, it seems to contradict S&P's comment that EG benefits from operating in a *"supportive regulatory framework."* It is clearly difficult to fathom why operating in one strong economic and regulatory environment would be riskier than operating in numerous jurisdictions, where several of these would possess lower regulatory support and/or weaker economies. And in fact, the 20 utilities included in Concentric's two *"most applicable"* OpCo samples also operate in only one jurisdiction, many with lower regulatory support and/or weaker economic environments than Ontario.

With respect to the second paragraph of Concentric's response, my evidence provided in Section 4 clearly shows that the US OpCo group is riskier than EG and hence the average equity ratio is uninformative, since it reflects this higher risk, as well as different regulatory practices and regimes. Section 4.4 demonstrates that seven of the utilities included in the Canadian OpCo sample are extremely small and their awarded equity ratios reflect this risk, and the average equity ratio for the three remaining utilities (which are also less than 5% of EG's size - which should also be accounted for) is 38%. In other words, the relatively larger equity ratios are driven by factors other than regulatory or regional diversity.

6.3 EG's Comparative Metric Analysis

On pages 103-104 of its evidence Concentric discusses credit metrics for Enbridge Gas and the four proxy groups, and reports these metrics in Figure 37 on page 104.

Exhibit I.5.3-IGUA-61(g) asked the following:

> *g) Please confirm that Concentric's credit metric analysis is based on the metrics of 13 of the 14 companies included in the two Holding Company samples, does not report or rely on metrics for the 10 companies included in the CanadianOpCo group, and uses only 7 of the 10 companies included in the USOpCo group. Please explain how such an approach, which heavily weights (i.e., uses 13 of 14) holding companies, and provides a much lower weighting to operating utilities (i.e., uses only 7 of 20), is consistent with Concentric's statement (on page 83) that the regulated operating company samples were the "most applicable for purposes of assessing Enbridge Gas' regulated equity thickness."*

The response was (emphasis added):

> *Figure 19 on page 66 of Concentric's report compares the 2021 S&P credit metrics for Enbridge Gas at both the total company and regulated only levels to the various proxy groups. This allows for comparison between Enbridge Gas and each of the Canadian holding company proxy group, the U.S. holding company proxy group, and the U.S. operating company proxy group. As noted below Figure 19,* ***there are insufficient companies in the Canadian operating company proxy group*** *that are rated by S&P to produce meaningful results.* ***Concentric does not place more importance or weight on one of these proxy groups than another for purposes of this comparison****. As discussed on pages 61-62 of Concentric's report, this analysis demonstrates that 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 group. This supports Concentric's conclusion on page 62 that Enbridge Gas' financial profile is relatively weak relative to its peer companies.*

The response indicates that Concentric equally weighted the credit metrics of the three proxy groups (including the two HoldCo groups it deemed as least applicable) that I have demonstrated (in Section 4) are **not** reasonable "similar risk" comparables to EG. It did not reference the credit metrics for the only reasonable proxy group, the Canadian OpCo group; albeit my analysis in Section 4.4 demonstrates that only three of these 10 utilities are even close to reasonable comparators. Therefore, aside from the presentation of the credit metrics for EG, Concentric's comparative metric analysis provides no meaningful information.

6.4 Higher Betas and Discounts

On page 109 of its evidence Concentric discusses betas with respect to Gas utilities trading at a discount to electric utilities. Concentric estimates betas using five years of historical weekly return observations at a particular point in time. It is also common practice to estimate betas using five years of monthy return observations, or two years of weekly return observations. Regardless of the chosen time period and frequency of return observations, these are "estimates" that are based on historical observations. As such, they will vary through time in response to changing market and company- and industry-specific events and return patterns. Concentric includes Figure 40, which includes Bloomberg beta coefficients.

On page 109, Concentric states that:

> *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.*

There are several issues with Concentric's conclusions:

1. It is not appropriate to make such judgments based on point estimates for betas, which fluctuate through time, and are statistically unreliable at any given point in time. This is obvious if one looks at the tables provided on page 1 of Attachment 1 included in Concentric's response to Exhibit I.5.3-STAFF-233, which shows that both the Bloomberg and Value Line adjusted beta estimates for both groups fluctuated greatly over this 11-year period. For example, the Bloomberg gas utility adjusted beta estimates ranged 0.6074 to 0.8617 over this period, while the electric utility estimates ranged from 0.5427 to 0.8920. Similarly, the Value Line gas utility adjusted beta estimates ranged from 0.65 to 0.89, while the electric utility estimates ranged from 0.59 to 0.90.
2. The adjusted beta estimates for gas utilities were **still lower** in 2022 than those for electric utilities, as they were in 2012.
3. The adjusted beta "estimates" for gas utilities **increased by almost the exact same amount** (+0.1346) as those for electric utilities (+0.1337) **–** the slightly higher percentage increase of 19.8% versus 18.4% noted by Concentric is not significant.

Based on this non-supportive evidence, on page 109, Concentric concludes that:

> *These analyses demonstrate that gas distribution utilities are, on average, trading at a discount to their electric utility peers.*

This conclusion is clearly unsupported by Concentric's evidence, which basically shows the opposite, if anything **–** i.e., betas for gas utilities are lower than those for electric utilities in 2022, as they were in 2012; although as pointed out above it is not appropriate to make such judgments based on point estimates for betas, which fluctuate through time, and are statistically unreliable at any given point in time.

In addition, Concentric also failed to provide any support for the assertion that high betas imply that stocks trade *"at a discount,"* as noted in the response to Exhibit I.5.3-IGUA-63(c), discussed below.

Exhibit I.5.3-IGUA-63(c) asked the following:

(c) Please explain why Concentric asserts that higher betas would indicate "a discount to their electric utility peers."

- *i) Please provide any academic or empirical support for this statement.*
- *ii) Would Concentric agree that financial theory would suggest that the prices of companies with higher betas would reflect these higher betas. If Concentric disagrees, please explain.*
- *iii) Over the period referenced by Concentric (i.e., 2012-2021), the data provided by Concentric in Exhibit 5 shows that stock returns on the TSX Index averaged 6.03%, and the S&P500 Index averaged 14.07%. Would Concentric agree that stocks with higher betas are more likely to display greater price increases than stocks with lower betas during such periods of positive market returns (i.e., since by the definition of beta their prices would be more likely to increase even more than the average market increase during upswings)? For example, stocks with high betas can frequently trade at huge (and sometimes unjustifiable) premiums relative to other stocks with lower betas, such as high-tech stocks did during the 1998-2001 period. If Concentric disagrees with this observation, please explain why.*
- *iv) Given that stocks with higher betas will, by definition, increase more than stocks with lower betas, please explain why Concentric argues that higher betas (if they exist) are indicative of stocks trading at a discount.*

The response was (emphasis added):

i) *Betas in Concentric's analysis were used to demonstrate changes in risk between 2012 and 2022. Please see response at Exhibit I.5.3-IGUA-50, which provides information on P/E ratios and a demonstration that LDCs have traded at a discount to electric utilities.*

(ii)-(iii) Concentric agrees that higher beta stocks would be expected to outperform lower beta stocks during an up market, and the corollary is true, low beta stocks would be expected to outperform high beta stocks during a down market. A company with a higher beta has greater risk and also greater expected returns.

(iv) *Please see the response to part c) i.*

So essentially, Concentric provided no empirical evidence or arguments to support the assertion that even if gas utilities had higher betas than electric utilities (which they don't – they are actually lower) that this would be indicative that they trade at a discount.

6.5 Canadian Utilities Trading at a Discount to US Utilities

On pages 112-113 of its evidence Concentric discusses equity reports and P/E ratios for Canadian and US utilities. Based on an examination of Figure 41, Concentric concludes that:

> *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.*

Exhibit I.5.3-IGUA-65 asked the following:

a) *Please confirm that over the period referenced by Concentric (i.e., 2012-2021), the data provided by Concentric in Exhibit 5 shows that stock returns on the TSX Index averaged 6.03% versus 14.07% (i.e., Canadian returns were 57.1% lower), while Canadian utilities returned an average of 9.03% versus 11.46% returned by US utilities (i.e., Canadian utility* *returns were only 20.3% lower). If not confirmed then please provide the actual numbers and percentages of difference.*

b) *Please confirm the P/E ratio for the TSX Index was 12.8 at the end of 2022, while the P/E ratio for the S&P500 Index was 18.6 (i.e., the TSX Index P/E was 31.1% lower); while at the end of 2012 the P/E ratio for the TSX Index was 15.8 and the P/E ratio for the S&P500 Index was 14.4 (i.e., the TSX Index P/E was 9.8% higher). If not confirmed then please provide the actual numbers and the percentage differences.*

c) *Given the fact that Canadian market returns were 57% lower than US market returns over this period, as reflected in the fact that the TSX Index P/E ratio was 31% lower than that for the S&P 500 at the end of 2022, versus having a 9.8% higher P/E ratio at the end of 2012, isn't it more reasonable to assume the small "discount" to Canadian utility P/Es in 2022 is mostly attributable to the weaker performance of the broader Canadian stock market relative to the US market, than to investors' assessments of the relative risk of Canadian versus US utilities? If not, please explain why not.*

The response was:

a) *Confirmed.*

b) *Concentric has not researched the P/E ratios for the TSX or S&P 500 Indexes in the preparation of its report.*

c) *Please see Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 112-114 of Concentric's report. On those pages, Concentric provides a summary of Scotiabank equity analyst findings regarding the convergence of Canadian and U.S. utility valuations, which Scotiabank related to similarities in U.S. and Canadian regulatory environments. Concentric tested Scotiabank's conclusions by updating the P/E ratio analysis conducted by ScotiaBank, and Concentric's analysis validated ScotiaBank's findings. Concentric understands, however, that other market forces, including returns in the broader market, impact returns on individual securities.*

In response to part (a), Concentric confirmed that overall market Canadian equity returns were 57% lower than US equity returns over this period, while Canadian utilities provided returns that were only 20% lower than US utilities. So if anything, such evidence contradicts the implication that Canadian utilities have performed relatively worse than US utilities. With respect to part (b), I can confirm the 2012 and 2022 P/E ratios referenced for both indexes are correct according to Bloomberg data. Concentric's response to part (c) does not directly address the question as posed. Based on the TSX and S&P index return and P/E data included in parts (a) and (b) of the question, I conclude that the small "discount" to Canadian utility P/Es in 2022 is in fact mostly attributable to the weaker performance of the broader Canadian stock market relative to the US market, rather than to investors' assessments of the relative risk of Canadian versus US utilities. In other words, the relatively lower P/E ratios for Canadian relative to US utility industry indexes in 2022 versus 2012 is largely a reflection of overall market returns.

This concludes my testimony.

CV

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Areas of Interest

Research: Empirical studies in corporate finance and investments.

Teaching: Investments, Business Finance and Corporate Finance. I have also taught numerous courses and delivered seminars in many preparatory programs designed to prepare students to write exams for all three levels of the CFA program and the CSC for over 10 years.

Education

University of Toronto	Ph.D., Finance, 1993 - January, 1998
Saint Mary's University	M.B.A., Finance, 1987-1989
Saint Francis Xavier University	B.Ed., Secondary, 1983-84
Acadia University	B.A., Economics, 1979-1983

Career Experience

Queen's University

Professor of Finance

Chair, Institute of Sustainable Finance (July 2018-present) Director of Master of Finance (July 2008 – June 2014; January 2017- December 2022)

Saint Mary's University

Associate Dean and Pengrowth Nova Scotia Professor in Petroleum Financial Management: (July 2007 – June 2008)

Professor: (September 2006 – June 2007)

Associate Professor: Finance (September 2000 - June 2001, July 2002 – August 2006)

Assistant Professor: Finance (July 1998 - August 2000)

Lecturer: Finance and Statistics, (1990-1993, Full Time)

York University

Assistant Professor: Finance (July 2001 – June 2002)

The University of Lethbridge — Assistant Professor: Finance (1997- 1998, Full Time)

The University of Toronto — Lecturer: Business Finance (Undergraduate and MBA) (1994-1997, Part Time)

Ryerson University — Lecturer: Investment Finance (1994-1997, Full Time)

WSC Investment Services — Instructor for CSC and CFA Seminars and Prepare Course Materials and Deliver Seminars for various professional organizations; (1996-present, Part Time)

Royal Bank of Canada — Commercial Lender; (1989-1990, Full Time)

Expert Witness Experience:

September 2019-April 2020 – Utilities Consumer Advocate (UCA) of Alberta
Prepared evidence regarding an appropriate ROE and capital structure for regulated Alberta utilities.

July-November 2018 – Newfoundland Consumer Advocate
Prepared evidence regarding an appropriate capital structure for Newfoundland Power.

September 2017-June 2018 – Utilities Consumer Advocate (UCA) of Alberta
Prepared and testified regarding an appropriate ROE and capital structure for regulated Alberta utilities.

April 2017-September 2018 – Utilities Consumer Advocate (UCA) of Alberta
Preparing evidence and testifying regarding appropriate risk margins for commodity risk for regulated Alberta utilities.

July-October 2016 – Manitoba Public Insurance
Prepared a report and testified regarding interest rate forecasts.

September 2015-July 2016 – Utilities Consumer Advocate (UCA) of Alberta
Prepared and testified regarding an appropriate ROE and capital structure for regulated Alberta utilities.

December 2015-June 2016 – Newfoundland Consumer Advocate
Prepared and testified regarding an appropriate capital structure for Newfoundland Power.

April-November 2014 – Utilities Consumer Advocate (UCA) of Alberta
Prepared and testified regarding appropriate risk margins for commodity risk for regulated Alberta utilities.

December 2013-August 2014 – Utilities Consumer Advocate (UCA) of Alberta
Prepared and testified regarding an appropriate ROE and capital structure for regulated Alberta utilities.

Publications:

Academic Journals:

"The Cost of Delaying to Invest: A Canadian Perspective," 2022, Forthcoming, Finance Research Letters. Co-authored with Neal Willcott, Smith School of Business, Queen's University.

"Post-Crisis M&As and the Impact of Financial Constraints" 2020. Journal of Financial Research, Vol 43 No. 2, 407-454. Co-authored with Ashrafee Hossain, Memorial University. Recipient of "Outstanding Article Award" for 2020.

"Institutional Investors, Monitoring and Corporate Finance Policies," 2017. International Journal of Managerial Finance, Vol. 13, Issue No. 2, 186-212. Co-authored with Jun Wang, The University of Western Ontario. Outstanding Paper Award.

"The Cash Effect and Market Reaction over Three Decades," 2016. Journal of Accounting and Finance, December 2016, 93-115. Co-authored with Fatma Sonmez, Queen's University.

"An Efficient and Functional Model for Predicting Bank Distress: In and Out of Sample Evidence," 2016. Co-authored with Greg Hebb, Dalhousie University. Journal of Banking and Finance, Vol. 64, March 2016, 101–111.

"Managerial Practices and Corporate Social Responsibility," 2015. Co-authored with Najah Attig, Saint Mary's University. Journal of Business Ethics, Vol. 131 (No. 1), 121-136.

"Organization Capital and Investment Cash Flow Sensitivity: The Effect of Management Quality Practices," 2014. Co-authored with Najah Attig, Saint Mary's University. Lead Article - Financial Management, Vol. 43 (No. 3), 473-504.

"Corporate Legitimacy and Investment-Cash Flow Sensitivity," 2014. Co-authored with Najah Attig, Saint Mary's University, Sadok El Ghoul, University of Alberta, and Omrane Guedhami, South Carolina University. Journal of Business Ethics, Vol. 121 (No. 2), 297-314.

"Debt Rating Initiations: Natural Evolution or Opportunistic Behavior?" 2013. Co-authored with Laurence Booth, University of Toronto, and Lynnette Purda, Queen's University. Journal of Modern Accounting and Auditing, Vol. 9 (No. 12), 1574-1595.

"Institutional Investment Horizons and the Cost of Equity Capital," 2013, Co-authored with

Najah Attig, Saint Mary's University, Sadok El Ghoul, University of Alberta, and Omrane Guedhami, South Carolina University. Financial Management, Vol. 42 (No.2), 2013, 441-477. Selected as one of 8 papers (since 2005) that was included in a Special Virtual edition on "Monitoring Management," 2018.

"Institutional Investment Horizon and Investment-Cash Flow Sensitivity." Co-authored with Najah Attig, Saint Mary's University, Sadok El Ghoul, University of Alberta, and Omrane Guedhami, South Carolina University. Journal of Banking & Finance, Vol. 36, (No. 4), 2012, 1164-1180.

"Capital Market Developments in the Post-October 1987 Period: A Canadian Perspective." Co-authored with Laurence Booth from the University of Toronto. Review of Accounting and Finance, Vol. 8 (No.2), 2009, 155-175.

"Cash Flow Volatility, Financial Slack and Investment Decisions," 2008, China Finance Review, Number 1, Vol 2, 63-86. Co-authored with Laurence Booth from the University of Toronto.

"The Investment Nature of Income Trusts and Their Role in Diversified Portfolios," Canadian Journal of Administrative Sciences. Co-authored with Greg MacKinnon from Saint Mary's University, (Vol 24(4)), 2007, 314-325.

"The U-Shaped Investment Curve: Theory and Evidence." Co-authored with Paul Povel, University of Minnesota, and Michael Raith, University of Southern California, Lead article, Journal of Financial and Quantitative Analysis, Vol. 42 (No. 1), March 2007, 1-39.

"Financial Constraints and Investment: An Alternative Empirical Framework." Co-authored with Bert D'Espallier, Hasselt University, Anales de Estudios Economicos y Empresariales, Vol. 17, 2007, 9-41.

"Dividend Smoothing and Debt Ratings." Co-authored with Laurence Booth and Varouj Aivazian, both from the University of Toronto. Lead article, Journal of Financial and Quantitative Analysis, Vol. 41(No. 2), June 2006, 439-452.

"International Corporate Investment and the Relationships between Financial Constraint Measures," Journal of Banking and Finance, Volume 30 (5), 2006, 1559-1580.

"Are U.S. Variables Good Predictors of Foreign Equity Risk Premiums?" 2006. Co-authored with John Schmitz, President, Sci-Vest Capital Management Inc., The Cyprus Journal of Sciences.

"Income Trusts: Past Performance and Future Prospects." Co-authored with Greg MacKinnon of Saint Mary's University. Canadian Investment Review, Winter 2005, 53-54.

"Dividend Policy and the Role of Contracting Environments" FSR Forum, December 2005, 13-20. Co-authored with Laurence Booth and Varouj Aivazian, both from the University of Toronto.

"Corporate Investment and Financial Slack: International Evidence," The International Journal of Managerial Finance, 2005, 140-163.

"Industry Affects Do Not Explain Momentum in Canadian Stock Returns," Investment Management and Financial Innovations, 2005(2), 49-60. Co-authored with John Schmitz, President, Sci-Vest Capital Management Inc., and David Doucette, Saint Mary's University.

"Do Emerging Market Firms Follow Different Dividend Policies from U.S. Firms?" The Journal of Financial Research, Fall 2003, 371-387. Co-authored with Laurence Booth and Varouj Aivazian, both from the University of Toronto.

"Dividend Policy and the Organization of Capital Markets." Journal of Multinational Financial Management, Spring 2003, 101-121. Co-authored with Laurence Booth and Varouj Aivazian, both from the University of Toronto.

"The Risk-Adjusted Performance of Closed-End Funds and the Impact of Discounts." Journal of Today, December 2002, 119-133. Co-authored with Greg Hebb of Dalhousie University and Greg MacKinnon from Saint Mary's University.

"Transactions Costs for TSE-Listed Stocks," Canadian Investment Review, Spring 2002, 20-26. Co-authored with John Schmitz, President, Sci-Vest Capital Management Inc., and Kevin Kerr, TD Securities, Toronto.

"What Has Worked on Bay Street," Canadian Investment Review, Winter 2001, 25-34. Co-authored with John Schmitz, President, Sci-Vest Capital Management Inc.

"The Sensitivity of Canadian Corporate Investment to Liquidity," Canadian Journal of Administrative Sciences, September 2000, 217-232.

"Diversification with Canadian Stocks: How Much is Enough?" Canadian Investment Review, Fall 1999, 21-25. Co-authored with David Copp, Mount Allison University.

"The Relationship Between Firm Investment and Financial Status," Journal of Finance, April 1999, 673-692. Received at least one vote from the editorial board for the top Corporate Finance Paper Award during the year of publication.

"Momentum in Canadian Stock Returns," Canadian Journal of Administrative Sciences, September 1998, 279-291. Co-authored with Michael Inglis, University of Toronto.

One of five nominations for "best 1998 CJAS paper."

Books and Book Chapters:

Introduction to Corporate Finance, first five editions, John Wiley & Sons Canada Limited. The first three editions were co-authored with Laurence Booth from the University of Toronto (2007, 2010, 2013), and the fourth and fifth editions (2016, 2020) co-authored with Laurence Booth and Ian Rakita from Concordia University. This is an Introductory Canadian Finance text that was written from "scratch."

Corporate Finance, First US Edition. Co-authored with Laurence Booth from the University of Toronto and Pamela (Petersen) Drake) from Virginia Commonwealth University. John Wiley & Sons. In progress – publication date 2013.

Investments: Analysis and Management, First, Second and Third Canadian Editions, co-authored with Charles P. Jones of North Carolina State University, John Wiley & Sons Canada Limited (1999, 2004, 2008). I was solely responsible for the development of all three Canadian editions, the first being based on an adaptation of the sixth U.S. edition, authored by Professor Jones.

The Canadian Securities Exam Fast Track Study Guide, First, Second, Third and Fourth Editions (2001, 2006, 2009, 2013) – sole author. Published by John Wiley & Sons Canada Limited.

Finance in a Canadian Setting, Sixth Edition, co-authored with Peter Lusztig and Bernard Schwab, both of the University of British Columbia, John Wiley & Sons Canada Limited, March, 2001. I was solely responsible for the development of this edition of the text, based on an adaptation of the fifth edition, authored by Professors Lusztig, Schwab and Randall Morck of University of Alberta.

Market Efficiency, a chapter in the CFA Institute Investment Series book entitled Investments: Principles of Portfolio and Equity Analysis (Wiley, 2011), which is currently used as CFA Level 1 material within the Candidate Body of Knowledge.

"Introduction to Financial Markets," (on-line course). Developed all seven modules for the Bourse de Montreal, 2002.

"Derivatives for the Retail Investor," (on-line course). Developed two modules (Forwards and Future, and Options) for the Bourse de Montreal, 2002.

"Derivatives for the Institutional Investor," (on-line course). Developed two modules (Options and Derivatives for Equity and Index Products) for the Bourse de Montreal, 2002.

"Investment Strategies and Asset Allocation," Chapter 5, Investment Management Techniques, The Canadian Securities Institute, 1999.

"Equity Securities," Chapter 12, Investment Management Techniques, The Canadian Securities Institute, 1999.

Cases:

"Time Value of Money: The Buy versus Rent Decision," with Stephen Foerster. Ivey Publishing, August 2014.

Conference Proceedings:

I have published numerous articles in conference proceedings, as summarized below:

European Financial Management Association annual conference, 2008, 2006, 2005, 2002.

Hawaii International Conference on Business, 2002.

Multinational Finance Society annual conference, 2001.

Atlantic Schools of Business annual conferences, 2000, 1998.

ASAC annual conferences, 2006, 2001, 2000.

Conference Best Paper Awards:

"The Information Content of Institutional Investment Horizon: Evidence from Firms' Implied Cost of Equity," 2012, Working Paper, Co-authored with Najah Attig, Saint Mary's University, Sadok El Ghoul, University of Alberta, and Omrane Guedhami, South Carolina University. Chosen Best Paper in Banking and Finance – 2012 European Business Research Conference.

"Income Trusts: Why All the Fuss and What About the Future?" 2006. Co-authored with Greg MacKinnon from Saint Mary's University. Chosen as the best paper in the Finance division for the 2006 ASAC Conference in Banff, Alberta.

"The U-Shaped Investment Curve: Theory and Evidence" 2004. Co-authored with Paul Povel, University of Minnesota, and Michael Raith, Rochester University. Presented at the 2004 NFA Conference and received award as the "Best Paper in Managerial Finance."

"The Sensitivity of Canadian Corporate Investment to Liquidity." Published in conference proceedings for the 1999 ASAC Conference in Saint John, New Brunswick.

Chosen as the best paper in the Finance division for this conference.

Conference Presentations:

Keynote Speaker (Finance Area) – ASAC 2012 Annual Conference.

I have presented papers at numerous conferences, as summarized below:

World Finance Conference, 2015, 2014, 2013, 2011, 2010.

Paris Financial Management Conference, 2014.

Northern Finance Association annual conferences, 2022, 2013, 2011, 2010, 2008, 2005, 2004, 2002, 2000, 1996.

Multinational Finance Society annual conferences, 2010, 2001, 1999.

European Financial Management Association annual conference, 2008, 2006, 2005, 2002.

Hawaii International Conference on Business, 2002.

Eastern Finance Association annual conferences, 2003, 2000.

Atlantic Schools of Business annual conferences, 2000, 1998, 1996.

ASAC annual conferences, 2006, 2000, 1999.

Financial Management Association annual conferences, 2013, 2011, 2010, 2008, 2005, 2004, 2001, 1999, 1996.

Southern Finance Association annual conference, 2022, 2016, 2008.

Finance Workshops (invited presentations):

Atlantic Canada CFA Society, 2006.

Melbourne Centre for Financial Studies, 2006.

Melbourne CFA Society, 2006.

Monash University (Caulfield), 2006.

University of Melbourne, 2006.

University of New South Wales, 2006.

University of Sydney, 2006.

University of Manitoba CGA Finance Conference 2005

Wilfred Laurier University, 2002.

University of Western Ontario, 2001.

York University, 2001, 2010.

Dalhousie University, 2001, 2013.

Queen’s University, 2000.

Saint Mary’s University, 2002, 2001, 2000, 1999.

Schulich School of Business, 2010.

Concordia University, 2013.

The University of Waterloo, 2015.

<u>Research Grants</u>

Co-investigator for an Insight Development Grant in the amount of $55,626 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 2016 to 2018 period (Principal investigator – Jun Wang of the University of Western Ontario).

Co-investigator for a Standard Research Grant in the amount of $129,980 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 2013 to 2017 period (Principal investigator - Najah Attig of Saint Mary’s University).

Awarded four Research Grants of $90,000 each over three years from the Smith School of Business at Queen’s University (2008-11; 2011-14; 2014-17; 2018-2020).

Principal investigator for a Standard Research Grant in the amount of $60,500 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 2008 to 2011 period.

Co-investigator for a Standard Research Grant in the amount of $111,000 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 2006 to 2009 period (Principal investigator - Najah Attig of Saint Mary's University).

Principal investigator for a Standard Research Grant in the amount of $70,118 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 2003 to 2006 period.

Awarded a Research Grant of $25,000 per year for three years from the Schulich School of Business at York University (July 2001).

Principal investigator for a Standard Research Grant in the amount of $61,530 from the Social Sciences and Humanities Research Council of Canada (SSHRC) for the 1999 to 2002 period.

Awarded Research Grant for $1,500 from Saint Mary's University (2003-2004).

Awarded Research Grant for 2,500 from Saint Mary's University (2002-2003).

Awarded Research Grant for $2,500 from Saint Mary's University (2000-2001).

Awarded Research Grant for $3,030 from Saint Mary's University (1999-2000).

Awarded Research Grant for $2,000 from Saint Mary's University (1998-99).

Research Grant in the amount of $20,000 from the Intellectual Infrastructure Partnership Program (IIPP) at the University of Lethbridge (1997-98).

Research Grant from the University of Lethbridge Research Fund for $4,500 (1997-98).

Work-in Progress

"The Leverage-Profitability Puzzle Revisited," 2018, Working Paper. Co-authored with Alan Douglas, and Tu Nguyen, both from the University of Waterloo.

"Does Dual Holdings by Institutional Investors Make a Big Difference?" 2018, Working Paper.

Co-authored with Jun Wang, the University of Western Ontario, and Keke Song, University of Melbourne.

"Leverage, Financial Flexibility, and Dividend Smoothing: An Empirical Investigation," 2018, Working Paper. Co-authored with Alan Douglas, the University of Waterloo.

Professional Activities

Member - CFA Society Toronto Advisory Council (January 2018-present)
Editorial Board – *Managerial Finance* (July 2017-present)
Associate Editor (Finance area) for the *Canadian Journal of Administrative Sciences* (2017-present); Editor (Finance area) (2014-2016).
Associate Editor for the *European Journal of Finance* (2008-present).
Editorial Advisory Board – Investor Lit (2013-present)
Senior Advisor – Toronto CFA Professional Development Committee (2014-2021); Chair (2013-14); Vice-Chair (2012-13)
Chair – Awards Committee – CFA Toronto Board of Directors (2008-2011)
President - Board of Directors for the Atlantic Canada CFA Society (2007-2008). Served on the board from 2001 to 2008.
Editorial Board – *Canadian Investment Review* (2008-2011).
Served as a reviewer for the *Review of Financial Studies*, the *Journal of Financial and Quantitative Analysis*, *Journal of Business, Financial Management, Journal of Money, Credit and Banking,* the *Journal of Banking and Finance,* the *European Journal of Finance*, the *Journal of Corporate Finance*, the *Journal of Applied Economics*, the *Multinational Finance Journal, Financial Review, Journal of International Financial Management,* the *International Review of Economics and Finance,* the *Canadian Journal of Administrative Sciences,* the *Review of Financial Economics, the Journal of Risk Finance,* and for the *Journal of Management and Governance*.
Reviewer for several SSHRC grant applications.
External reviewer/examiner for several tenure and renewal applications received for professors at other universities, as well as for Ph.D. dissertations.
Conference chair for 2001 Northern Finance Association Annual Meeting, held in Halifax.
Conference organizing committee and Reviewer for several conferences.
Completed the Chartered Financial Analyst (CFA) program, and awarded the CFA designation.
Completed the Professional Financial Planning Course offered by the Canadian Securities Institute, as well as the Canadian Securities Course (CSC).

Completed the Investment Funds Institute of Canada's Mutual Fund Course.

Prepared course materials for several "on-line" finance courses.

Instructor for Canadian Securities Course Seminars.

Prepared Course Materials for the Canadian Securities Institute.

Delivered Seminars for the Canadian Securities Institute on the Canadian Securities

Course (CSC), Fixed Income Securities and Portfolio Management Techniques.

Student Supervision

External Examiner for several PhD students.

Supervisor, Queen's PhD Finance Students, Neal Willcott 2019-present, and Dhruv Baswal 2022-present.

Supervisor, Queen's MSc Finance Students, Aashray Kaudinya 2022-present, Dhruv Baswal 2022, Ehsan Dehghanizadeh 2019, Wayne Charles 2010.

Served as co-director for the Investment Management of Portfolios in Atlantic Canada Training Program (IMPACT) at Saint Mary's University. This innovative program has students manage a portfolio of over $150,000 of "real" money (2005-2008).

Served as faculty advisor to several MBA students preparing their Management Research Project (MRP) in finance (FIN 669) to satisfy their MBA requirements:

Robert March, "Using Canadian and US Macroeconomic Variables to Predict Canadian Equity Risk Premiums" (1999).

Simon Sagar, "Do Canadian Investors Overreact?" (2000). Simon also presented his paper at the 1999 Atlantic Schools of Business (ASB) conference in Halifax.

Kevin Kerr, "Bid-Ask Spreads and Commissions on the TSE" (2000).

Scott LeBlanc, "An Investigation of Derivative Use: A Case Study of Cambior Inc." (2000).

David Doucette, "Industry Momentum in Canadian Stock Returns" (2001).

Balakrishna Murty, "The Effect of Board Composition on Firm Value: Some Canadian Evidence" (2003).

Bashir Jallow, "US Economic Factors and International Equity Risk Premia Predictability" (2005).

Kathy Isnor, "The Effect of Corporate Governance Policies on the Corporate Bond Rating" (2005).

References

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Form A: Acknowledgement of Expert's Duty

Sean Cleary

Ontario Energy Board

FORM A

IN THE MATTER OF an Application by Enbridge Gas Inc. to change its natural gas rates and other charges beginning January 1, 2024.

ACKNOWLEDGEMENT OF EXPERT'S DUTY

1. My name is Sean Cleary I live at 539 Golfview Court (*city)*, in the Town of Oakville (*province/state*) of Ontario.

2. I have been engaged by or on behalf of the Industrial Gas Users Association to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date April 12, 2023

____

Signature

Prepared Direct Testimony:
James M. Coyne

Prepared for:
Liberty Utilities (Gas New Brunswick) LP

Before the:
New Brunswick Energy and Utilities Board

March 31, 2021

PREPARED DIRECT TESTIMONY:

JAMES M. COYNE

PREPARED FOR:

LIBERTY UTILITIES (GAS NEW BRUNSWICK) LP

BEFORE THE:

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

MARCH 31, 2021

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TABLE OF CONTENTS

I. INTRODUCTION

A. Qualifications

My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am testifying on behalf of Liberty Utilities (Gas New Brunswick) LP ("Liberty"), which provides natural gas distribution service in New Brunswick. Liberty is a wholly-owned subsidiary of Liberty Utilities (Canada) LP, which in turn is indirectly owned by Algonquin Power & Utilities Corp ("APUC").

I am one of Concentric's professionals who provide expert testimony before U.S. and Canadian federal, state and provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utility companies, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes estimating 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. I have testified or provided expert evidence in over 50 proceedings in Canada and the U.S., including 16 cost of capital proceedings in Canada.

I am 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, I 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, I 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. I have been an invited speaker for several CAMPUT events including the Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation."

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

B. Scope of Report

I have been asked to provide an estimate of the cost of capital and a recommended equity ratio for Liberty, as well as to assess the reasonableness of Liberty's debt cost. In order to estimate the cost of capital, I have relied on analytical tools and data sources commonly used for such purposes by regulators in Canada and the U.S. I have also reviewed past decisions of the New Brunswick Energy and Utilities Board (the "Board"), including the 2010 decision that established Liberty's current authorized ROE of 10.9 percent and deemed equity ratio of 45.0 percent and the 2016 decision that determined that Liberty was no longer in the development period once the general franchise agreement expired in 2019. The analysis provided in this report supports my overall recommendation on the cost of equity and capital structure.

C. Report Organization

The remainder of this report is organized as follows: Section II summarizes my ROE and equity ratio recommendations; Section III summarizes the legal requirements and key regulatory precedents for setting a fair return; Section IV reviews the business and economic conditions in Canada and the U.S. and how they have changed since the 2010 decision was issued by the Board; Section V describes my proxy groups and my proxy group screening criteria; Section VI discusses the methods used to estimate the cost of equity and summarizes the results of the DCF, CAPM and Risk Premium analyses; Section VII discusses the business and financial risks of Liberty, both in terms of how those risks have changed since 2010 and how those risks compare to the proxy group companies, and my recommended equity ratio for Liberty; and in Section VIII, I summarize my conclusions and recommendations.

II. ROE AND EQUITY RATIO RECOMMENDATION

A. Approach

An assessment of the appropriate return for Liberty relies on the fundamental legal and regulatory principle that a utility must be given a reasonable opportunity to earn a fair return on its invested capital. In order for the rate of return to be judged fair, Liberty must be provided with a reasonable opportunity to earn a return that meets three standards:

- the comparable investment standard;
- the financial integrity standard; and
- the capital attraction standard.

These standards must be met individually and in total to satisfy the fair return standard.

My analysis includes the selection of three proxy groups, a Canadian group, a U.S. gas group, and a North American group, with companies reasonably comparable to Liberty with respect to business and financial risks. I have estimated the cost of equity for Liberty using the discounted cash flow ("DCF"), capital asset pricing ("CAPM"), and bond yield plus risk premium ("risk premium" or "equity risk premium") models, with alternative inputs and model specifications designed to test the reasonable range of results. In doing so, I look for evidence of consistency between models and results. The results of methods I have relied upon are summarized in Figure 1. Based on these analyses, I developed a range of results for each of the proxy groups.

In addition, I performed a risk assessment of Liberty currently in relation to Liberty's risks at the time of the Board's 2010 decision, the last time the Board established these parameters for Liberty, and I also assessed Liberty's risk relative to the proxy groups for purposes of determining the appropriate deemed equity ratio.

As shown in Figure 1, the average results from the various models and proxy groups cover a range from 9.9 percent to 11.5 percent using the forward-looking CAPM, and from 9.6 percent to 11.0 percent using an Alternative CAPM analysis which uses a market risk premium based on the average of projected and historical return data for both Canada and the U.S. As discussed in my risk assessment, a higher ROE than the average is justified based on the relative risk of Liberty in relation to the proxy group companies. I therefore consider 11.5 percent, the average upper end of the proxy results for the Canadian Proxy Group using the forward-looking CAPM, most appropriate for Liberty. This reflects a 160 basis point differential over the lower risk U.S. proxy group benchmark using the forward-looking CAPM, which I believe is appropriate for a company of Liberty's risk profile.

Figure 1: Summary of Mean Results[1]

	CANADIAN UTILITY PROXY GROUP	U.S. GAS PROXY GROUP	NORTH AMERICAN PROXY GROUP
CONSTANT GROWTH DCF	12.05%	9.58%	10.95%
MULTI-STAGE DCF	10.92%	8.97%	10.05%
FORWARD-LOOKING CAPM	11.61%	11.44%	11.54%
ALTERNATIVE CAPM	10.12%	9.97%	10.06
RISK PREMIUM		9.71%	
AVERAGEWITH FORWARD-LOOKING CAPM	**11.5%**	**9.9%**	**10.8%**
AVERAGE WITH ALTERNATIVE CAPM	**11.0%**	**9.6%**	**10.4%**

B. Recommendation

These recommendations are based on a cost of capital analysis utilizing the DCF, CAPM and Risk Premium models, and a combination of U.S., Canadian and North American proxy group companies. I have also considered the Board's regulatory precedents, including the 2016 determination that Liberty is no longer in the development period, Liberty's business and financial risks, and issues around the Development O&M deferral account and the Regulatory

1 Results include 50 basis points for flotation costs and financing flexibility, except for Risk Premium results for U.S. proxy group.

deferral account. Based on the foregoing, I recommend an authorized return for Liberty of 11.5 percent. Given the risk profile of Liberty relative to other companies in the Canadian and U.S. comparator groups, an equity ratio of 50.0 percent is my recommendation. This ratio is still below the average of larger and lower risk U.S. gas distributors, but higher than other Canadian gas distributors justified by a smaller customer, throughput and revenue profile which imposes greater business risk. These recommendations meet both the requirements of the fair return standard and stand-alone principle, as well as provide sufficient support for the financial integrity and soundness of Liberty.

III. LEGAL REQUIREMENTS AND KEY REGULATORY PRECEDENTS FOR THE DETERMINATION OF A FAIR RETURN

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company were established by the Supreme Court of Canada 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.[2]

The 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 indicated that:

> 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

[2] *Northwestern* at p. 186.

> become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[3]

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). 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.[4]

With the passage of time, the "fair return standard" has been interpreted many times in both Canada and the U.S. In Canada, for example, 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

3 Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
4 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

> the Mainline's revenue requirement, result in tolls that are just and reasonable.[5]

B. The Stand-Alone Principle

The stand-alone principle provides that a utility should be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. In order to establish a fair return and satisfy the Stand-Alone Principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits.

C. The Relationship Between Capital Structure and ROE

The cost of common equity depends in part on the company's capital structure. The equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the additional financial risks. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity. As fixed debt obligations increase, the equity buffer (unencumbered earnings available to shareholders) narrows and the required equity return increases to compensate investors for the additional risk to earnings. The fair return, therefore, depends on both the equity return and capital structure.

The risk to the earnings stream of the utility is a function of both its business and financial risks. Business risk refers to the political and regulatory environment that the utility operates within and the operational and competitive forces that could potentially exert pressure on earnings. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risks therefore need to be considered when setting the capital structure.

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

IV. BUSINESS AND ECONOMIC CONDITIONS

A. Summary and Relevance to Utility Cost of Capital

Utilities raise debt and equity in an increasingly global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis. Projections of real GDP growth, inflation and interest rates are direct inputs to the cost of capital models. Likewise, the cost of equity for regulated utilities is influenced by factors such as central bank policy, investor confidence, and uncertainty and volatility in financial markets. Each of these factors is discussed in this section of my report, starting with macroeconomic conditions in Canada and the U.S,

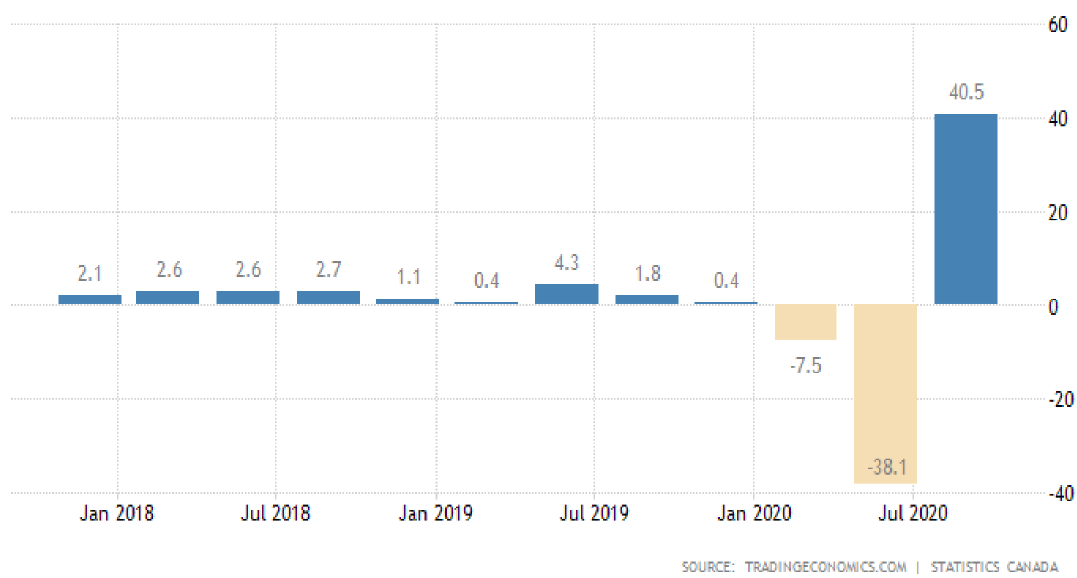
B. Economic Conditions

At the time of the 2010 filing by EGNB, the economy in both Canada and the U.S. was just beginning to recover from the effects of the financial crisis and the Great Recession. Central banks in both Canada and the U.S. would subsequently provide additional monetary stimulus in the form of Quantitative Easing, which was designed to lower interest rates on the long-end of the yield curve. As of February 2021, the economies in both Canada and the U.S. are expected to emerge from sharp contractions in 2020 that were precipitated by the COVID-19 pandemic, which forced the closure of many businesses as economies went into lockdown to control the spread of the virus. A vaccine has been developed and is being distributed in both countries, and there is hope for economic improvement, particularly in the second half of 2021. However, extraordinary policy measures were necessary from central banks and federal governments in both Canada and the U.S. to stabilize the financial system in the immediate aftermath of the pandemic, to support economic growth, and to provide additional unemployment benefits to those in industries most affected by COVID. This policy response caused a precipitous drop in interest rates on government and corporate bonds. Those bond yields, however, have been increasing steadily since July 2020 as investors anticipate the economic recovery.

1. Canada

The Canadian economy experienced steady but slow economic growth in 2018 and 2019. However, as shown in Figure 2, the economy in Canada contracted sharply in the first and second quarters of 2020, as many businesses and schools were forced to close to limit the spread of COVID-19. Real GDP declined at an annualized rate of 7.5 percent in the first quarter of 2020, followed by a decline of 38.1 percent in the second quarter, which represents the sharpest contraction ever over the period from 1961 through 2020, according to Statistics Canada. Economic growth rebounded in the third quarter of 2020 at an annual rate of 40.5 percent, also the largest percentage increase over the past 60 years.

Figure 2: Canadian Real GDP Growth[6]

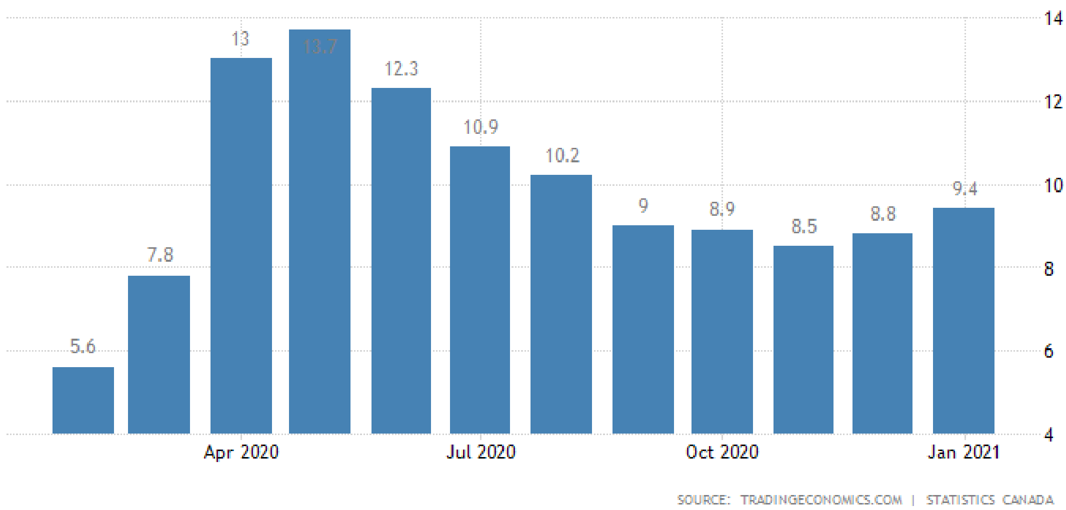


As shown in Figure 3, the unemployment rate in Canada increased from 5.6 percent in February 2020 to 13.7 percent in May 2020, which represents the highest level for unemployment in Canada over the period from 1966-2020. The rate declined steadily over the remainder of 2020, but increased again in January 2021 and currently stands at 9.4

[6] Trading Economics, https://tradingeconomics.com/canada/gdp-growth-annualized

percent.[7] Consumer prices in Canada have been weak, increasing at an annual rate of 1.0 percent between January 2020 and January 2021.[8]

Figure 3: Canadian Unemployment Rate



2. <u>United States</u>

After experiencing steady economic growth from 2017-2019, measures taken to contain COVID-19 and associated impacts on business and consumer behavior forced the U.S. economy into a sharp recession in 2020. As shown in Figure 4, according to the Bureau of Economic Analysis, real GDP decreased at an annual rate of 5.0 percent in the first quarter of 2020 and at a startling annual rate of 31.4 percent in the second quarter before rebounding in the third quarter at an annual rate of 33.4 percent. The "advance" estimate for the fourth quarter shows GDP expanded at an annual rate of 4.0 percent.

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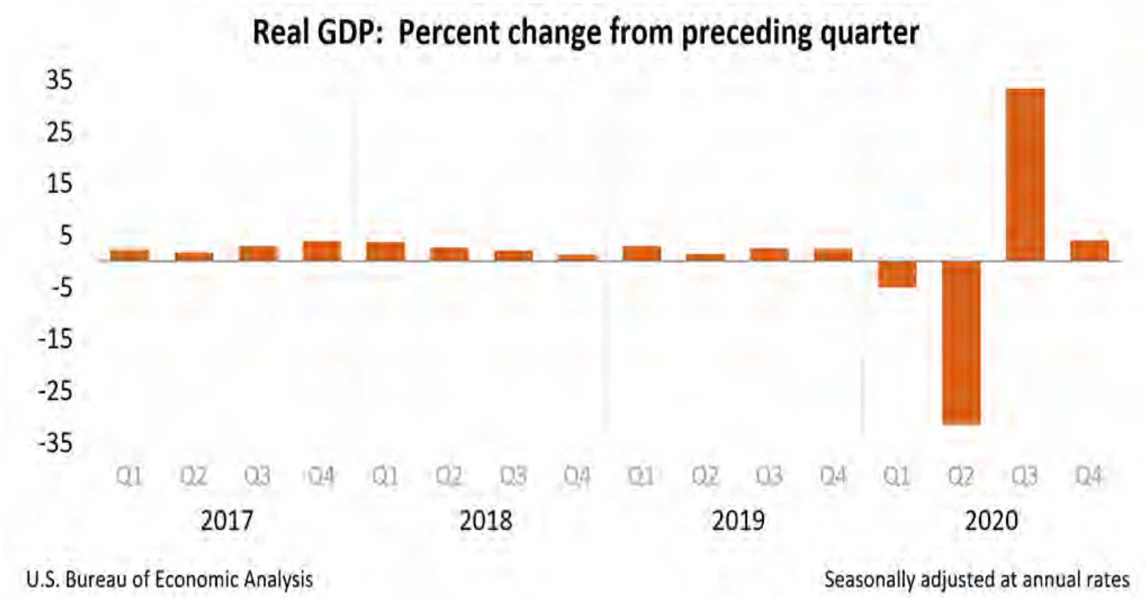
7 Trading Economics.
8 Trading Economics.

Figure 4: U.S. Real GDP Growth[9]



As shown in Figure 5, the U.S. unemployment rate steadily declined over the past ten years from 9.1 percent in January 2011 to 3.6 percent in December 2019. After reaching a low of 3.5 percent in January 2020, the unemployment rate spiked to 14.8 percent in April 2020 as businesses were forced to close due to COVID-19, before steadily falling to 6.3 percent in January 2021 as most businesses were allowed to re-open and many sectors of the economy returned to something closer to normal.[10] Further, the Consumer Price Index increased at an annual rate of 1.8 percent in 2019 and 1.2 percent in 2020. The average annual increase in consumer prices from 2011 through 2020 was 1.73 percent.[11]

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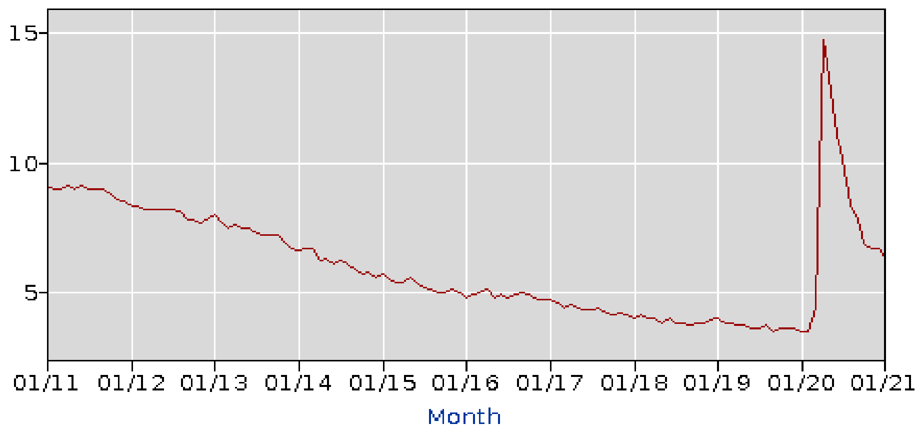
[9] U.S. Bureau of Economic Analysis, https://www.bea.gov/data/gdp/gross-domestic-product
[10] Source: U.S. Bureau of Labor Statistics, February 25, 2021.
[11] *Ibid.*

Figure 5: U.S. Unemployment Rate



C. Policy Response of Central Banks and Federal Government

In response to the economic effects of COVID-19, central banks and federal governments in both Canada and the U.S. took aggressive steps to stabilize financial markets in the Spring of 2020 and to provide ongoing support for the economies of both countries.

1. Canada

On March 4, 2020, the Bank of Canada ("BOC") announced a 50 basis point reduction in the overnight target rate from 1.75 percent to 1.25 percent. The BOC explained its rationale as follows:

> Before the outbreak, the global economy was showing signs of stabilizing, as the Bank had projected in its January Monetary Policy Report (MPR). However, COVID-19 represents a significant health threat to people in a growing number of countries. In consequence, business activity in some regions has fallen sharply and supply chains have been disrupted. This has pulled down commodity prices and the Canadian dollar has depreciated. Global markets are reacting to the spread of the virus by repricing risk across a broad set of assets, making financial conditions less accommodative. It is likely that as the virus spreads, business and consumer confidence will deteriorate, further depressing activity.[12]

[12] Press release: Bank of Canada lowers overnight rate target to 1 ¼ percent, March 4, 2020.

This was followed by two further reductions of 50 basis points each in the BOC's overnight rate target on March 16, 2020 and March 27, 2020, bringing the overnight rate target from 1.25 percent to 0.25 percent where it has remained.

The federal government has taken aggressive steps to provide fiscal stimulus to support the Canadian economy during the course of the COVID-19 pandemic. These programs have specifically targeted financial assistance for those who are unemployed, as well as tax reductions for individuals and businesses. *The Wall Street Journal* ("WSJ") reported that Canada had spent approximately $382 billion on these measures. In addition, the federal government announced plans to inject another $100 billion into the Canadian economy over the three years following the recession to ensure the sustainability of the economic recovery. While this policy response has provided crucial support for the Canadian economy, the WSJ also noted that it has caused the budget deficit to swell to approximately $381.6 billion, or 17.5 percent of GDP, as compared with a deficit equal to 1.7 percent of GDP in the previous 12 month period. Due to concerns over the rapid increase in Canada's spending, Fitch downgraded the credit rating for Canada in June 2020 from AAA to AA+. However, S&P and Moody's have maintained their AAA rating for Canada.[13]

In its January 2021 Monetary Policy Report, the BOC indicated that its economic projections depend on important assumptions about how the pandemic will evolve. In particular, the BOC noted:

> Canada and many countries are experiencing a setback in their economic recoveries. Rapid increases in the number of COVID-19 infections have prompted governments to impose stricter containment measures and lockdowns (Chart 1). However, an earlier-than-anticipated start to vaccination programs has pulled forward the timeline for achieving broad immunity and improved the outlook for growth in the medium term. Until the virus is under control and there is no need for physical distancing, the recuperation phase of the economic recovery will likely remain choppy and uneven. Considerable fiscal and monetary stimulus continue to be required to support households and businesses.[14]

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[13] The Wall Street Journal, "Canada's COVID-19 Response is to Spend Heavily and Ignore the Deficit – For Now," December 1, 2020.

[14] Bank of Canada, Monetary Policy Report, January 2021, at 1. (Chart 1 omitted)

In the same report, the BOC underscored three key messages about the outlook for the Canadian economy:[15]

1) The Canadian economy had strong momentum going into the last quarter of 2020, but the resurgence of the virus and the reintroduction of extensive lockdown measures are now restraining economic activity and imposing new hardships on households and businesses. Growth in the first quarter of 2021 is expected to be negative.

2) Unemployment in Canada remains elevated, particularly for workers in high-contact service industries. These workers will once again be the hardest hit by the lockdown measures.

3) With vaccines being rolled out earlier than anticipated, the recuperation in the Canadian economy is now more secure, and medium term growth is forecast to be stronger. Nevertheless, considerable economic slack remains in the economy, and a complete recovery will take some time. As result, inflation is not anticipated to return sustainably to its 2 percent target until 2023.

2. United States

In response to the economic effects of COVID-19, the Federal Reserve decreased the federal funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent and also announced plans to increase its holdings of both Treasury and mortgage-backed securities. In addition, on March 23, 2020, the Federal Reserve began expansive programs to support credit to large employers, including the Primary Market Corporate Credit Facility to provide liquidity for new issuances of corporate bonds, and the Secondary Market Corporate Credit Facility to provide liquidity for outstanding corporate debt issuances. Further, the Federal Reserve supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.[16] These bond buying programs by the Federal Reserve

[15] Ibid, at 2.
[16] Federal Reserve Board Press Release, "Federal Reserve announces extensive new measures to support the economy," March 23, 2020.

provided $700 billion in liquidity to financial markets, through purchases of government and corporate bonds and mortgage-backed securities.

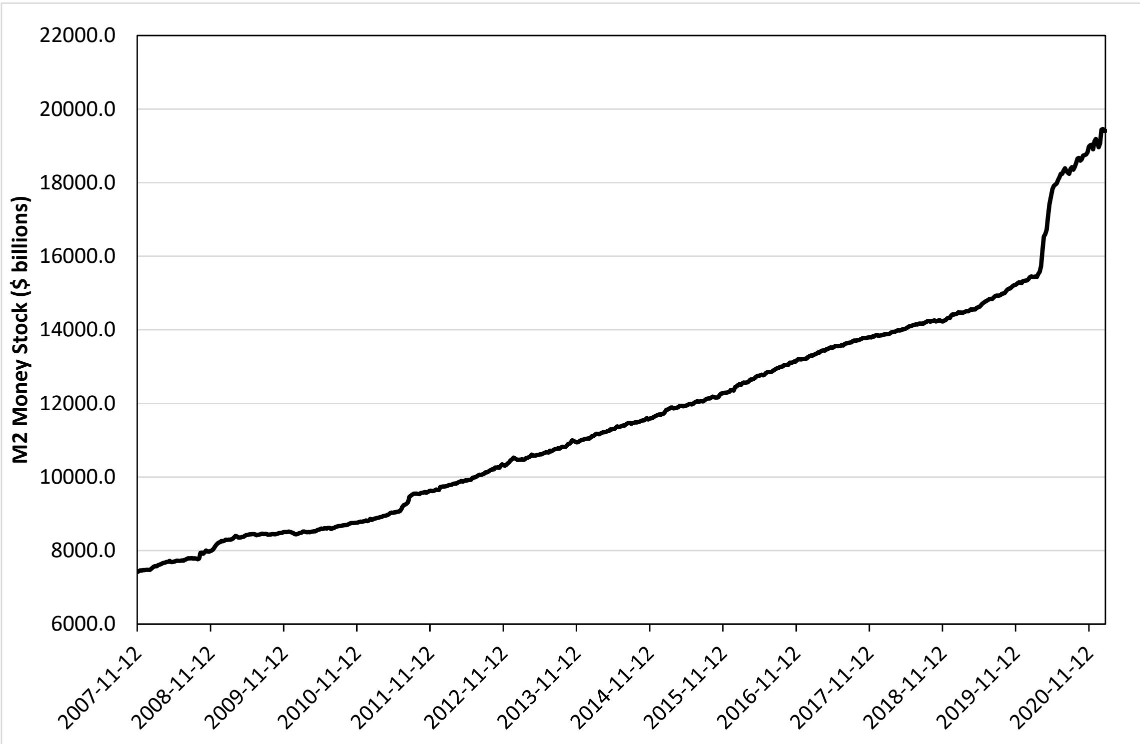
In addition to the Federal Reserve's response, the U.S. Congress also passed fiscal stimulus programs. On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security Act was signed into law, providing a large fiscal stimulus package aimed at mitigating the economic effects of the coronavirus. While these expansive monetary and fiscal programs have provided for greater price stability, volatility in equity markets remains well above long-term historical levels and is expected to remain above long-term historical levels over the near-term. The extraordinary measures taken by the Federal Reserve to stabilize the economy and financial markets have thus far been successful, but in doing so have driven investors from very low yielding bonds into equities, creating upward pressure on valuations and downward pressure on yields for dividend paying companies such as utilities. Furthermore, the U.S. Congress recently approved additional stimulus of $1.9 trillion in response to the ongoing economic effects of COVID-19. Additional fiscal stimulus is likely to increase pressure on the inflation rate, and the bond market may be at risk of a sharp upward spike in interest rates if inflation is higher than currently anticipated by investors.

These programs allow the Federal Reserve to purchase government and corporate bonds from banks. The banks then receive cash from the Federal Reserve, which results in an expansion of the money supply. This increase in the money supply keeps short-term interest rates low and increases the ability of banks to lend to consumers and businesses. Investors in longer term bonds also respond, which affects the entire duration of the yield curve, from very near-term rates all the way out to 30-year yields. Continued access to capital is particularly important in current market conditions because it allows companies to offset the negative effects of COVID-19 on business operations. Figure 6 shows that the programs enacted by the Federal Reserve have resulted in an unprecedented expansion of the money supply as measured by M2[17] in recent months. That expansion has been much greater than the increase following the Federal Reserve's response to the Great Recession of 2008/2009.

[17] M2 is defined by the Federal Reserve as follows: M2 includes a broader set of financial assets held principally by households. M2 consists of M1 plus: (1) savings deposits (which include money market deposit accounts, or MMDAs); (2) small-denomination time deposits (time deposits in amounts of less than $100,000); and (3) balances in retail money market mutual funds (MMMFs).

This again demonstrates the level of intervention that was necessary to provide some stability to markets.

Figure 6: M2 Money Stock – September 2009 – February 2021[18]



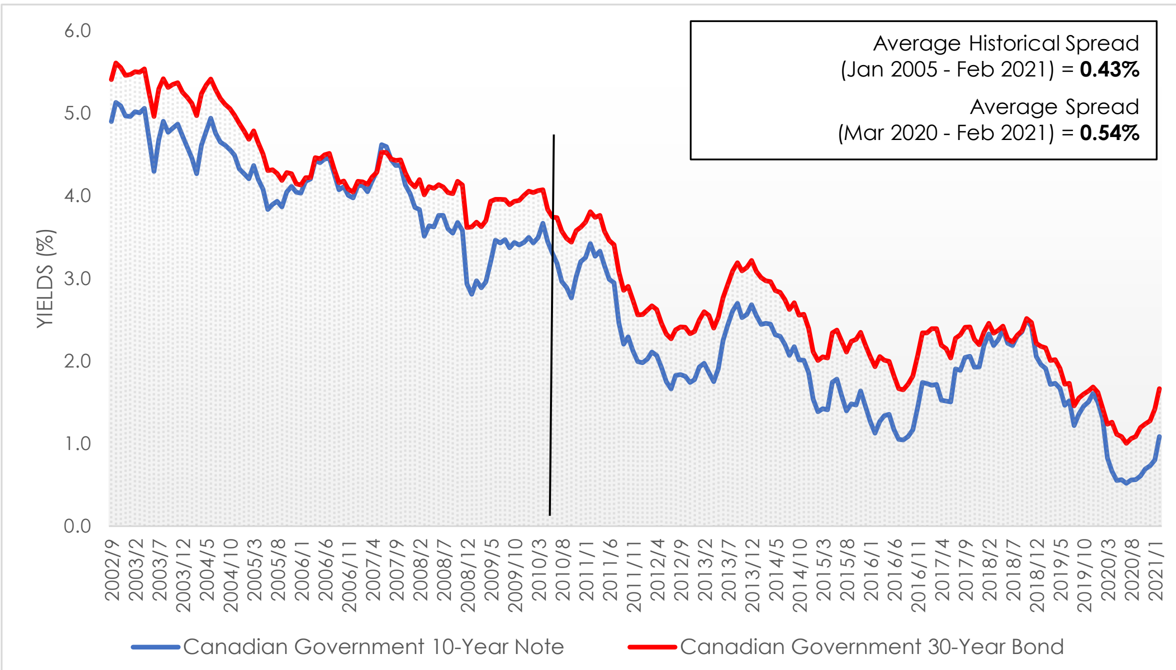
D. Interest Rates

The 10- and 30-year long-term Canadian government bond yields of 3.30 percent and 3.74 percent, respectively, in June 2010 (approximating the time when the Board last considered evidence on the cost of capital for Liberty), moved lower to an average of 1.08 percent and 1.66 percent in February 2021. The spreads between 10- and 30-year Canadian government bonds increased from 44 basis points ("bps") in June 2010 to 58 bps in February 2021, above the historical average of 43 bps from January 2005 through February 2021. As Figure 7 shows, the overall decline in bond yields for both the Canadian 10- and 30-year government bonds reversed sharply in the latter part of last year after trading at or near all-time lows in July 2020. Continuing this more recent trend, current 10 and 30 year Canadian bond yields

18 Board of Governors of the Federal Reserve System (US), M2 Money Stock [M2], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/M2, February 1, 2021.

stand at 1.49 percent and 1.95 percent, as of March 24, 2021. As explained in a subsequent section of this testimony (see Risk Free Rate), I have utilized a forecast 10-year bond yield and current 10-30 year bond spread in the CAPM and Risk Premium models to produce a forward-looking cost of capital analysis.

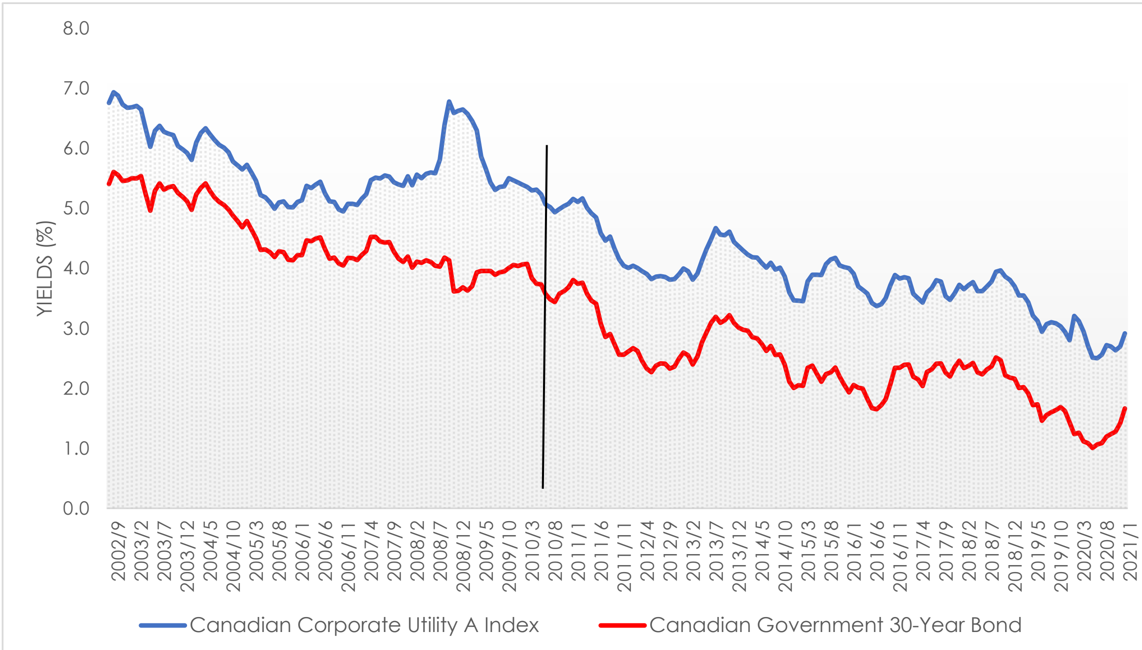
Figure 7: Canadian Government Bond Yields - 10-Year and 30-Year[19]



Measured against 2010, yields on corporate bonds have also declined since June 2010. As Figure 8 illustrates, the Canadian Utility "A" rated bond yield index was 5.31 percent in June 2010 compared to 2.91 percent in February 2021, after reaching a low of 2.50 percent in August 2020.

[19] Bloomberg series GCAN10YR and GCAN30YR as of February 26, 2021.

Figure 8: Canadian Utility "A" Rated Bond vs. 30-Year Canada Long Bond[20]



According to Consensus Economics' Long-Term Financial Forecast, shown in Figure 9, Canadian and U.S. 10-year government bond yields are expected to rise gradually to reflect movement towards more normalized economic policy in the respective economies. Notably, Canadian government bond yields are projected to exceed those in the U.S. starting in 2022 and continuing through the forecast period (i.e., 2030).

Figure 9: Long-Term Forecast for 10-Year Government Bond Yields[21]

	2021	**2022**	**2023**	**2024**	**2025**	**2026-2030**
Canada	1.1	1.6	2.0	2.4	2.7	2.9
U.S.	1.1	1.5	1.8	2.1	2.4	2.7

20 Bloomberg series C29530Y and GCAN30YR as of February 26, 2021.
21 Consensus Forecasts by Consensus Economics Inc., Survey Date October 12, 2020, at 3 and 28.

E. Yield Curve

While the BOC and Federal Reserve have communicated their intention to keep short-term interest rates low for an extended period, this does not have a direct bearing on long-term interest rates, although their purchases of long-term bonds can moderate long-term rates. One of the leading indicators used by investors to determine what stage of the business cycle the economy is in is the yield curve, which measures the difference between long-term and short-term interest rates. A flat or inverted yield curve occurs when long-term interest rates are equal to or less than short-term interest rates, which usually occurs prior to a recession, while a steepening yield curve occurs when the difference between long-term interest rates and short-term interest rates is increasing and indicates that the economy is entering a period of economic expansion following a recession.[22]

I calculated the difference between the yield on the 10-year Treasury bond and the 2-year Treasury bond from January 2016 to February 2021. I selected the 10-year Treasury bond yield to represent long-term interest rates and the 2-year Treasury bond to represent short-term interest rates. As shown in Figure 10, the yield curve has been steepening in the U.S. since June 2020 and has increased to approximately 130 bps, which is a level not seen since January 2017. The steepening yield curve indicates that investors expect economic growth and inflation to increase in the near-term. As a result, they are expected to rotate out of long-term government bonds to avoid being locked into low interest rates for the long-term. The steeper yield curve signals that higher yields are required by investors to invest in long-term government bonds.

[22] "What is a yield curve", Fidelity.com. https://www.fidelity.com/learning-center/investment-products/fixed-income-bonds/bond-yield-curve

Figure 10: 10-year U.S. Treasury Bond Yield Minus 2-year Treasury Bond Yield

January 2016 – February 2021[23]

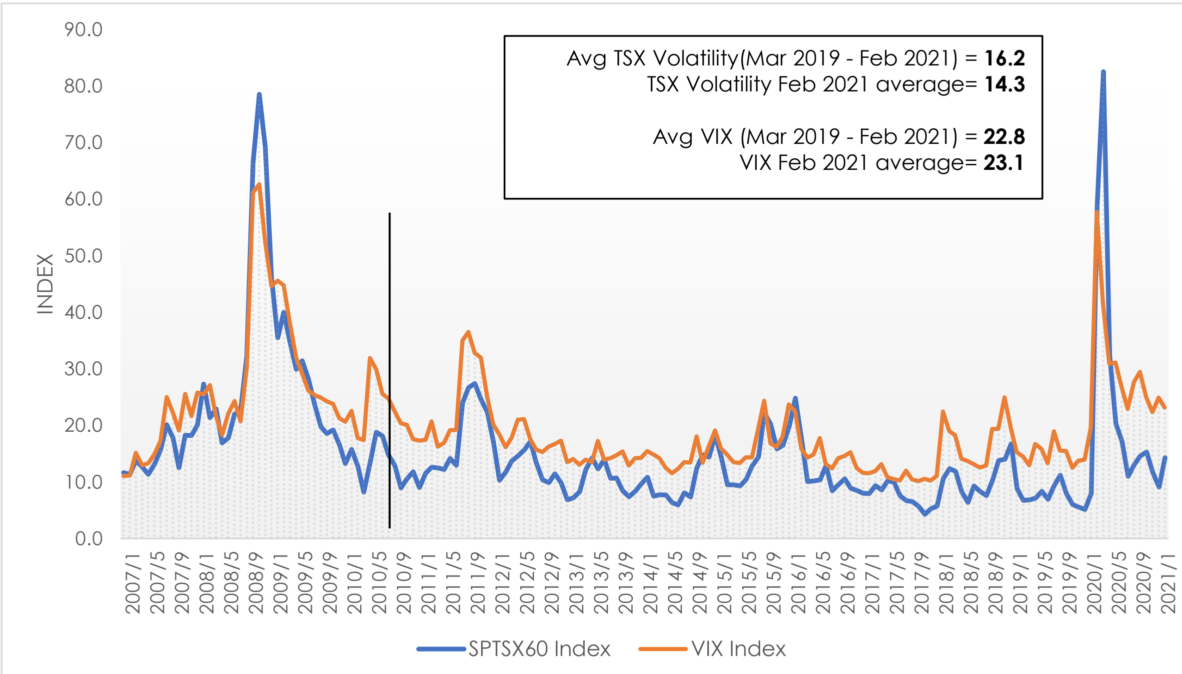
F. Volatility in Equity Prices

Stock prices in both Canada and the U.S. fell sharply from mid-February through April 2020, as investors reacted to fears over a global pandemic (the spread of COVID-19) and a sharp decline in crude oil prices. The TSX Composite Index declined by approximately 30 percent from February 20, 2020 through March 12, 2020, while the S&P 500 decreased by nearly 27 percent over the same period. Shares of utility companies also fell in both countries, with the TSX Utilities Index down by more than 26 percent and the S&P Utilities Index off by more than 23 percent. At the same time, volatility in equity markets spiked to levels not seen since the financial crisis and Great Recession of 2008-2009. As shown in Figure 11, the implied volatility for the Canadian equity markets (as measured by the TSX Volatility Index) rose to an average of 82.50 in April 2020, while in the U.S. implied volatility (as measured by the VIX) followed a similar path, rising to an average of 57.74 in March 2020. Volatility has since

23 Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10Y2Y, February 26, 2021.

receded in both countries, but remains above the long-term monthly median since January 2007 of 12.41 in Canada and 17.37 in the U.S.

Figure 11: Canadian and U.S. Volatility Indexes[24]



This sudden and dramatic spike in implied volatility in 2020 reflected the prevailing uncertainty and fear among equity investors. While volatility in equity markets declined in both Canada and the U.S. after it became apparent to investors that the aggressive monetary and fiscal policy response was having the desired impact on the economy and financial markets, there is ongoing uncertainty as reflected by the fact that volatility remains above the long-term median level in both countries. This is important because the equity risk premium increases when volatility is at elevated levels.

G. High Valuations and Low Dividend Yields

The levels of long-term government bond yields have affected the valuations of utility shares in both Canada and the U.S. As shown in Figure 12, the 30-year Canadian government bond yielded more than 4.00 percent in 2008. Long Canada bond yields have declined steadily

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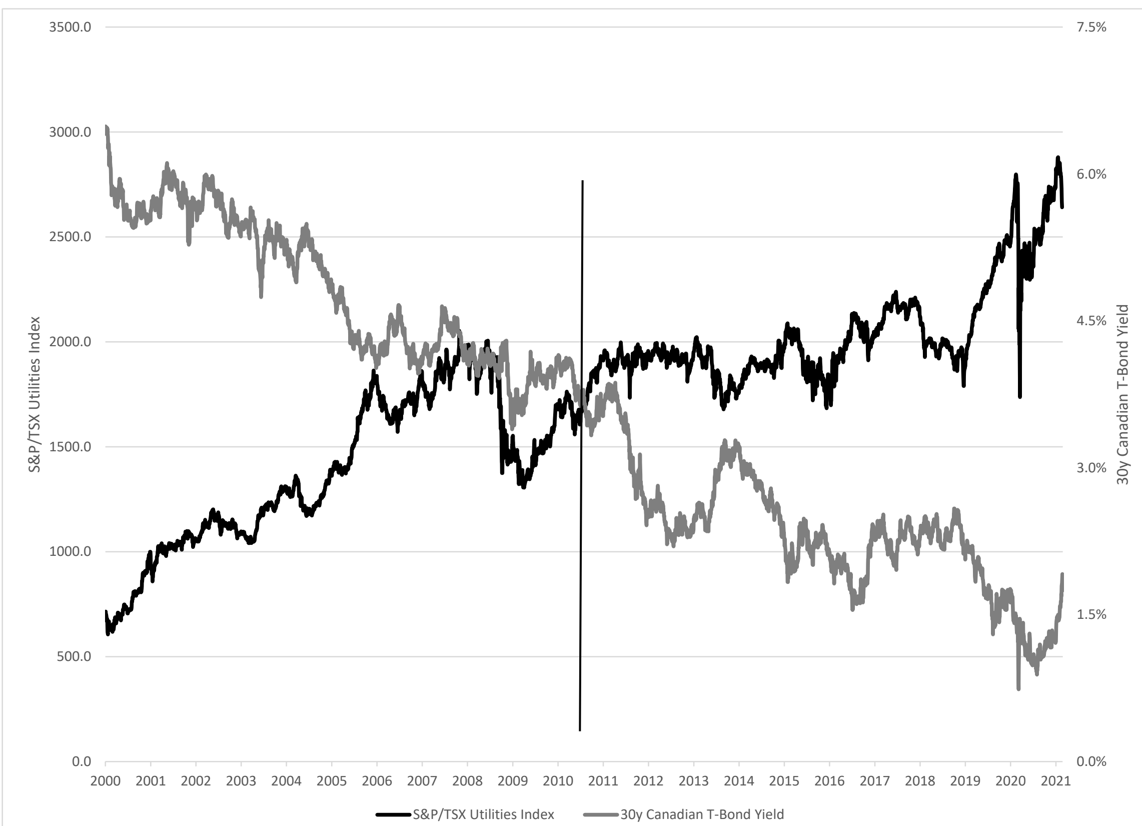
[24] Bloomberg Professional. Data through February 26, 2021.

since then as central banks in Canada and around the world pursued a policy of monetary policy accommodation. In response, the TSX Utilities Index increased substantially as dividend paying stocks became more valuable to investors due to their higher dividend yields compared to yields on long Canada bonds. After reaching a trough in the summer of 2016, government bond yields in Canada started increasing and utility shares, as measured by the TSX Utilities Index, became less attractive relative to government bonds. More recently, the TSX Utilities Index declined sharply in March of 2020 in response to concerns over COVID-19, but has rebounded to new highs in recent weeks. Yields on 30-year Canadian government bond also fell sharply in the spring of 2020 as central banks eased monetary policy to offset the economic effects of the pandemic, but interest rates have increased in 2021 to levels last seen in May 2019 as investors anticipate an economic recovery.

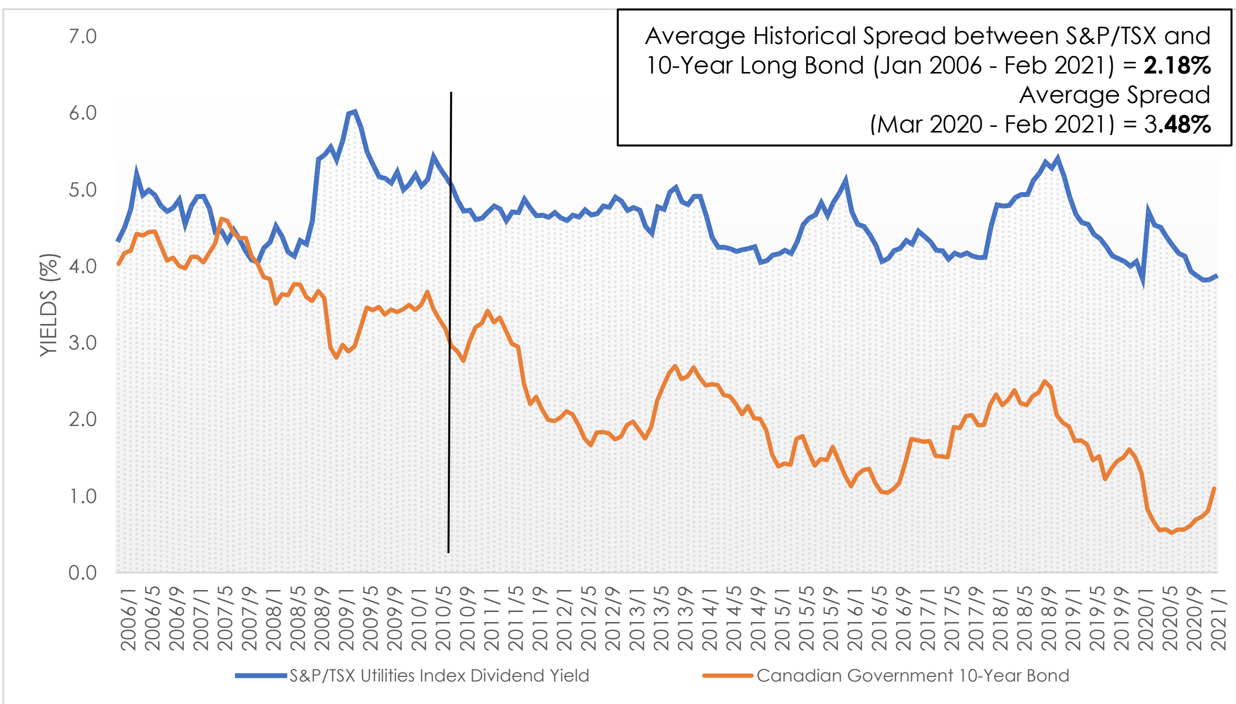
Figure 12: TSX Utilities Index vs. 30-year Canadian Gov't Bond Yield[25]



[25] Bloomberg Professional as of February 26, 2021.

Another aspect of this relationship is observed with utility dividend yields, which historically have enjoyed a high degree of correlation with government bond yields. However, since the Great Recession in 2008-2009 they have diverged. This trend is illustrated in Figure 13. The average spread between the S&P/TSX Utilities Index dividend yield and the 10-year Government of Canada bond yield was 3.48 percent from March 2020 through February 2021, compared with 2.18 percent between January 2006 and February 2021. One interpretation is that investors are expecting higher government bond yields in the future, so rather than take the risk of rising rates diminishing the value of government bonds, they are favoring a low-risk substitute—utilities. Another interpretation is that investors understand that government bond yields are responding to unique circumstances and actions of the central banks, and are not indicative of the risks of utility investments.

Figure 13: S&P/TSX Utilities Index Dividend Yield vs. 10-Year GOC Bond Yields[26]



While not a perfect substitute, due to the low interest rate environment, investors seeking an alternative to the low yields on government bonds have been purchasing the stocks of dividend-paying companies such as utilities. This has caused the valuations of utility stocks

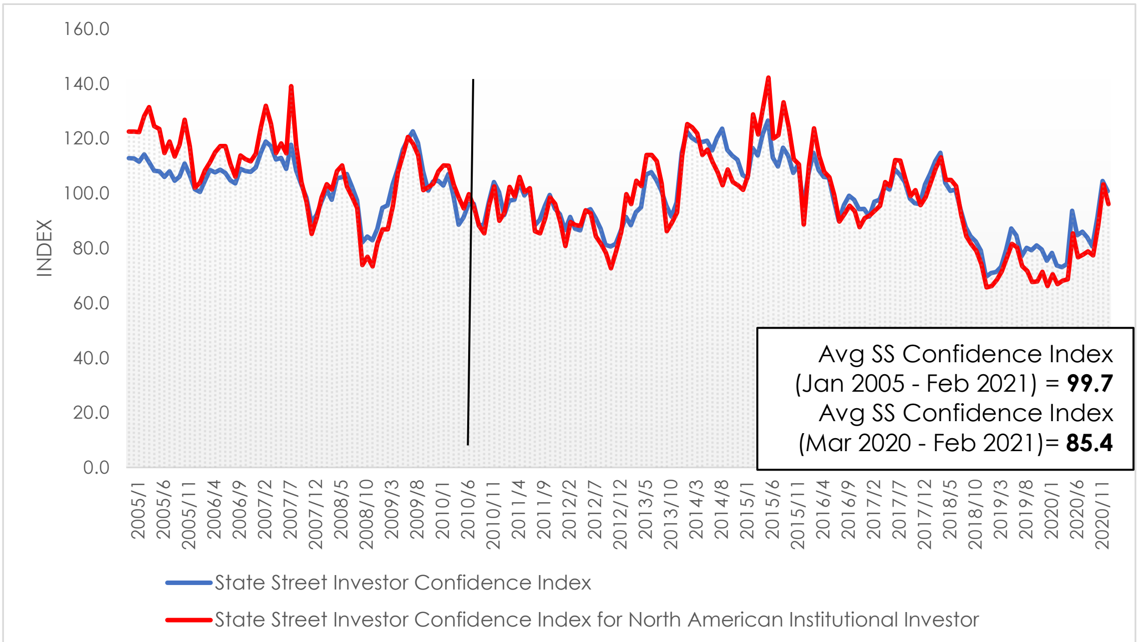
[26] Bloomberg Series STUTILX and GCAN10YR as of February 26, 2021.

in both Canada and the U.S. to increase rather substantially since 2009, while the dividend yields for these companies have declined. However, according to industry analysts such as Value Line, these high valuations are not expected to continue, as P/E ratios are projected to decline from current levels in the period from 2021-2025.

H. Investor Confidence

The investor confidence index, published by State Street Bank in the U.S., provides a quantitative measure of global risk tolerance. The index assesses investor confidence by reviewing the risk of investor portfolio investments. Figure 14 shows that investor confidence in 2020 was generally lower than during the global economic crisis of 2008-2009. After peaking in May 2018 at 114.80, investor confidence turned sharply lower and remained below 100 from September 2018 through December 2020. In February 2021, the State Street index stood at 100.80, compared to 88.52 in June 2010 in the aftermath of the financial crisis. Its path suggests greater confidence in a post-COVID economic recovery.

Figure 14: State Street Investor Confidence Indices[27]



I. Integration of Canadian and U.S. Capital Markets

In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic and business environments.

Country-specific economic and business conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by a prominent international research and credit group, COFACE, ranks Canada and the U.S. precisely the same from a Country Risk perspective (A3) and Business Risk perspective (A1), with A1 being the highest ranking.[28]

27 Bloomberg SSICCONF Index and SSICAMER Index as of February 26, 2021.
28 https://www.coface.com/cofaweb/comparer/268-703

	UNITED STATES OF AMERICA	CANADA
POPULATION	328.5 million	37.5 million
GDP PER CAPITA	65,254 US$	46,272 US$
COUNTRY RISK ASSESSMENT	A3	A3
BUSINESS CLIMATE ASSESSMENT	A1	A1
WATCH		
STRENGTHS	• Flexible labour market • Full employment is one of the Federal Reserve's objectives • The dollar's predominant role in the global economy • 70% of public debt held by residents • Highly attractive: leader in research & innovation, huge market • Favourable corporate taxation	• Abundant and diversified energy and mineral resources • Fifth-largest oil and gas producer in the world • Strong, well-capitalised and well-supervised banking sector • Fiscal rigour • Immediate proximity to the large U.S. market • Development of trade relations (CETA with the EU) • Excellent business environment
WEAKNESSES	• Low labour market participation • Households not geographically flexible • High household debt (129% of gross disposable income) • Polarised political landscape • Decrease in fertility rate • Outdated infrastructure • Growing inequalities	• Dependent on the U.S. economy (1/2 of FDI stock, integration of the two countries' automotive industries) and energy prices • Loss of competitiveness in manufacturing companies due to low labour productivity • Insufficient R&D expenditure • Decrease in the share of the working population, only just slowed down by high selective immigration • High household debt (158% of disposable income in mid-2020) • Rapid growth in property prices • Energy exports weakened by inadequate supply pipelines to the coasts and the United States, and by the U.S.'s own resources

This suggests that from a business investment perspective, Canada and the U.S. are highly comparable in an increasingly global investment context.

The magnitude and significance of trade between the two countries reflects the high degree of economic interdependence. 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. The United States and Canada traded goods and services worth $725 billion in 2019 – nearly $2 billion per day. 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."[29] Canada is currently the U.S.' 2nd largest goods trading partner overall with $612.1

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[29] U.S. Department of State, https://www.state.gov/u-s-relations-with-canada/#:~:text=The%20United%20States%20and%20Canada%20traded%20goods%20and%

billion in total (two way) goods trade during 2019.[30] This is an indication of the high degree of integration between the two economies.

Exhibit JMC-2 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 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. My cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. I therefore consider both Canadian and U.S. proxy companies for my analysis.

J. Capital Market Conclusions

Although interest rates on government and corporate bonds have declined in recent years, that does not necessarily suggest that the cost of equity has declined. On the contrary, these lower interest rates are symptomatic of investor concerns about future economic growth in both countries and indicate more near-term uncertainty and higher risk for investors in equity markets as suggested by higher volatility. In addition, interest rates in both Canada and the U.S. are projected to increase from current levels over the next two to three years, as shown by the Consensus Economics forecasts. These risks are signaled by a steepening in the yield curve, as bond yields rise and investors begin to anticipate the economic recovery.

Prior to 2020, the pace of economic growth was relatively slow in both countries as compared with previous recoveries, and in Canada there was elevated concern about future economic growth in oil-producing provinces such as Alberta and Saskatchewan. Interest rates on Canadian and U.S. government and corporate bonds moved higher in 2018 before declining in 2019 due to concerns that global trade tensions might derail the economic expansions in

20services%20worth,more%20than%2030%20U.S.%20States.

[30] https://ustr.gov/countries-regions/americas/canada.

both countries. The economic landscape changed in February 2020 with the COVID-19 pandemic causing a sharp decline in equity prices, a sharp increase in volatility, and aggressive monetary and fiscal stimulus in both Canada and the U.S. As a result of these stimulus measures, markets stabilized and stock prices began moving higher, although the utility sector tended to underperform relative to most other sectors of the economy because the demand for electricity and natural gas was negatively affected among commercial and industrial customers. In 2021, interest rates on government and corporate bonds have moved higher as signs emerge that economic growth will pick up in the second half of the year. In addition, concerns are rising among investors that inflation will be higher than expected as central banks and governments continue to provide monetary and fiscal stimulus to ensure that the economic recovery is sustained once the COVID-19 pandemic subsides.

These macroeconomic and financial market conditions indicate that, while interest rates on government and corporate bonds have declined, the cost of equity has increased because investors perceive higher risk of negative economic outcomes across Canada and the U.S. The decline in yields on Canadian government and corporate bonds reflects this economic uncertainty and elevated risk, but does not suggest that the cost of equity capital has decreased. My conclusions on the changes in economic and capital market conditions are consistent with the results of my financial models, which indicate that the cost of equity for a benchmark distribution utility is higher than the ROE authorized by the Board in the 2010 decision.

V. SELECTION OF PROXY COMPANIES

A. Proxy Group Selection

Since the ROE is a market-based concept, it is necessary to establish a group of companies that is both publicly traded and comparable to Liberty in fundamental business and financial respects to serve as a "proxy" for purposes of ROE estimation. As demonstrated later in this section, the proxy companies used in the ROE analyses possess a set of business and financial characteristics that are similar to Liberty, and thus provide a reasonable basis for the development of ROE estimates.

Notwithstanding the care taken to ensure comparability, market expectations with respect to future risks and growth opportunities vary from entity to entity. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate in the context of that range. That determination must be based on an assessment of the entity-specific risks relative to the proxy group and the informed judgment and experience of the analyst.

B. Precedent for Considering U.S. Data

Canadian regulators have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian utilities is limited by the small number of publicly traded utilities in Canada and by the fact that many of those Canadian utilities derive a significant percentage of revenues and net income from operations other than regulated service.

The British Columbia Utilities Commission ("BCUC"), for example, has accepted the use of U.S. proxy group data in Canadian ROE analysis, primarily due to the lack of sufficient Canadian data, and in recognition of the need for Canadian utilities to compete for capital in a global marketplace.[31] The CER (formerly the NEB), the OEB and the Régie de L'Energie (Quebec) have also accepted the use of U.S. data and proxy groups for purposes of establishing the allowed ROE and common equity ratio for Canadian electric and gas utilities.[32] In summary, multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes.

While there may have been a time when Canadian utilities were considered less risky than U.S. utilities, that perception has changed among investors over the past decade. For example,

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31 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 15-16.

32 National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 66-72; Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23; and English translation of Régie de l'Energie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

in a September 2013 report, Moody's Investors Service ("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.[33]

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."[34]
- "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."[35]
- "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."[36]
- "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

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[33] 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.
[34] *Ibid.*, at 4.
[35] *Ibid.*
[36] *Ibid.*

viable utilities in their states while balancing the needs of the state's commercial, industrial and residential utility customers."[37]

- "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."[38]

C. Proxy Groups

I developed three proxy groups for the ROE analysis. The screening results and business profiles of the proxy companies are presented in Exhibit JMC-3. The first proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Recognizing that there are relatively 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. I believe an inclusive Canadian proxy group of companies with significant distribution operations benefits my analysis by bringing additional Canadian market perspective. However, I note that several of the Canadian utility companies have an expanding presence in the U.S. with significant recent acquisitions of U.S. utility companies. The only Canadian company that I excluded from the proxy group is Algonquin Power & Utilities Corp., the parent of Liberty, as it is my general practice to exclude the subject company or its parent from the proxy group due to the circularity it would otherwise create. The following companies comprise the Canadian Utility Proxy Group:

[37] *Ibid*.
[38] *Ibid*., at 5.

Figure 15: Canadian Utility Proxy Group

Company	Ticker	Sector
AltaGas Ltd.	ALA	Gas
Canadian Utilities Limited	CU	Electric/Gas
Emera, Inc.	EMA	Electric/Gas
Enbridge Inc.	ENB	Gas/Pipeline
Fortis, Inc.	FTS	Electric/Gas
Hydro One Ltd.	H	Electric

The second proxy group is comprised of U.S. gas distribution utility companies. To obtain companies of like-risk to Liberty, and also to ensure that candidate companies have sufficient data to perform the DCF and CAPM analyses, I used a number of screens to develop a group of companies that are primarily engaged in the provision of regulated gas distribution service. Starting with the 10 companies Value Line classifies as Gas Utilities, I further screened for companies that meet the following criteria:

1. Investment grade credit rating from S&P (i.e., BBB- or higher);
2. Consistently pay quarterly cash dividends;
3. Positive earnings growth rate projections from at least two sources;
4. At least 70 percent of operating income derived from regulated operations in the period from 2017-2019;
5. At least 90 percent of regulated operating income derived from gas distribution service in the period from 2017-2019; and
6. Not involved in a merger or other significant transformative transaction during the evaluation period.

The following four U.S. gas utility companies met the screening criteria:

Figure 16: U.S. Gas Utility Proxy Group

Company	Ticker
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Corporation	SWX
Spire, Inc.	SR

The credit rating screen is important because the rating agencies focus on the utility's business risk profile (which includes an assessment of the regulatory environment in which the utility operates) and its financial risk profile. Companies with similar credit ratings are considered by the rating agency to have similar levels of business and financial risk as it pertains to the risk of default on company debt. It should be noted that risk of default is very different than earnings risk to shareholders, although the primary factors impacting those risks are generally the same. The credit rating screen has been accepted by regulatory agencies, including the Federal Energy Regulatory Commission ("FERC"), which 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."[39]

The dividend payment screen assures that companies have a stable business and dividend history allowing the calculation of the dividend yield which anchors the DCF model. The availability of earnings growth projections from two or more analysts indicates sufficient coverage to provide a more balanced perspective on the company's business and earnings outlook than a single analyst could provide. The operating income screen assures that the majority of the corporate entity's income is derived from regulated utility operations, resulting in proxy companies better reflecting the lower risk profile of a regulated utility. To further focus the proxy group on companies with Liberty's risk profile, I additionally screen for over 90 percent of operating income from the regulated gas distribution business. The final screen for companies involved in mergers avoids the problem of market data that has been distorted by the inevitable price movements prior to and following a merger announcement.

[39] See, for example, *Potomac-Appalachian Transmission Highline, LLC*, 122 FERC ¶ 61,188 at p. 97 (2008).

The third proxy group is a combined North American proxy group, consisting of each of my Canadian utility companies and the four U.S. gas distribution utilities, as detailed in Figure 17.

Figure 17: North American Utility Proxy Group

Company	Ticker
AltaGas Ltd.	ALA
Canadian Utilities Limited	CU
Emera Inc.	EMA
Enbridge Inc.	ENB
Fortis Inc.	FTS
Hydro One Inc.	H
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Corporation	SWX
Spire, Inc.	SR

VI. THE COST OF EQUITY METHODS AND THEIR RELIABILITY

A. Methods for Determining ROE

Regulated utilities primarily use common stock and debt to finance their investments in property, plant, and equipment and working capital.[40] The overall rate of return ("ROR") for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their percentage of the total capitalization of the company. While the costs of debt and preferred stock can be directly observed, the

[40] Liberty is a wholly-owned subsidiary of Liberty Utilities (Canada) LP, which in turn is indirectly owned by Algonquin Power & Utilities Corp ("APUC"). Liberty's equity is controlled through partnership units owned by the parent limited partnership. On February 14, 2020, Liberty Utilities (Canada) LP, the parent of Liberty, issued C$200 million of senior unsecured debentures bearing interest at 3.315% with a maturity date of February 14, 2050. The debentures received a rating of BBB from DBRS. From these proceeds, Liberty Utilities (Canada) LP loaned C$155 million to Liberty, replacing its higher cost credit facilities.

cost of equity is market-based and, therefore, must be estimated based on market information.

The required ROE is estimated using one or more analytical techniques to quantify investor expectations regarding required equity returns. Quantitative models produce a range of reasonable results from which the market-required ROE is selected. That selection must be based on a comprehensive review of relevant data and information and does not necessarily lend itself to a strict mathematical solution. As a general proposition, the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general and the subject company (in the context of the proxy group) in particular. I have considered the results of the CAPM, DCF and Risk Premium methods in developing an ROE recommendation for Liberty.

B. Importance of Using Multiple Approaches

Analysts and academics understand that ROE models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. No model can exactly pinpoint the correct ROE. Rather, each model brings its own perspective and set of inputs that inform the estimate of ROE. That position is consistent with the *Hope* finding that "[u]nder the statutory standard of 'just and reasonable,' it is the result reached, not the method employed, which is controlling."[41]

Although each model brings a different perspective and adds depth to the analysis, each model also has its own set of inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Changes to inputs can have significant impacts on the results of the various analyses. This view is widely held among financial practitioners, including me.

Regardless of which analyses are performed to estimate the investor's required return on equity, the analyst must apply judgment to assess the reasonableness of results and to determine the best weighting to apply to results under prevailing capital market conditions. The DCF, CAPM and Risk Premium methods are relatively simple models to estimate the cost

[41] Hope, op. cit.

of capital, which by its nature is complex. No one model can reliably estimate the cost of capital that meets the criteria of the fair return standard. Only by applying multiple tests and employing reasonable judgment can we be assured of a reasonable estimate of the required return on equity.

In its 2010 decision, the Board recognized the merits of the Equity Risk Premium method (with a primary focus on the CAPM) which utilizes market-derived inputs to estimate the forward-looking ROE, while dismissing the results of the DCF model as "not appropriate for the circumstances of the present case."[42] As discussed above, investors use multiple methodologies to estimate the cost of equity because each model has certain strengths and weaknesses, depending on the circumstances of the specific company as well as capital market conditions. The Constant Growth form of the DCF model was developed by Professor Myron Gordon in the 1960s for the purpose of estimating the cost of equity for companies in mature industries, such as public utilities, where it was reasonable to assume that those companies' dividends and share prices would increase at a constant rate in perpetuity. Due to the small number of publicly traded utility companies in Canada, and due to limited coverage of certain companies by equity analysts, the data needed to perform the DCF model was not as readily available for a Canadian proxy group in 2010 as it is today. Therefore, it was necessary to introduce a U.S. proxy group of utility companies that were considered comparable to Enbridge Gas New Brunswick. However, there were concerns at that time that U.S. utility companies were higher risk than their Canadian counterparts, so Canadian utility regulators were reluctant to accept the use of U.S. data to set the return for Canadian utility companies without making an adjustment. Those concerns have been mitigated to a large degree in the past decade, as there is broader analyst coverage of Canadian utility companies, and as credit rating agencies and equity investors no longer perceive U.S. utility companies as higher risk compared to those in Canada.

The DCF model is widely used in regulatory proceedings in the U.S., although the DCF model is currently challenged by dividend yields of many utility companies being suppressed by the very low interest rate environment. The Constant Growth form of the DCF model can be used to estimate the cost of equity for companies in mature industries, such as regulated utilities,

42 New Brunswick Energy and Utilities Board, Cost of Capital for Enbridge Gas New Brunswick L.P., Decision issued November 30, 2010, at 4.

and the Multi-Stage DCF can be used when there is concern that short-term growth rates may not be sustainable over the longer-term. For all of these reasons, I find that it is reasonable and appropriate to consider the results of the CAPM, DCF and Risk Premium models to estimate the cost of equity for Liberty in this proceeding.

C. Methods Used to Determine Cost of Equity

1. Capital Asset Pricing Model

a. Approach

The CAPM analysis (one form of equity risk premium approach) is a market test, based on a theoretically derived relationship between a security's required return and the systematic risk of that security. A risk premium, adjusted for the specific risk of a company or investment, is added to an underlying "risk free" rate (*e.g.*, a government bond). The CAPM analysis is premised on the concept that investors will diversify away risk that diverges from the risk of the overall market. The amount of risk that remains after diversification is referred to as the non-diversifiable risk or "systematic risk." Beta is the risk factor applied to the market risk premium to account for the risk of the individual security that is not diversifiable, measuring the extent to which the security returns move in tandem with the market. This can further be explained by the individual stock's contribution to the total risk of the portfolio. As shown in Equation [1], to calculate the CAPM, one must incorporate estimates of the risk-free rate of return, the market risk premium and Beta. Since the CAPM is forward looking, it is appropriate to use forward-looking assumptions for the variables, when possible.

$$[1] \quad Ke = rf + \beta(rm - rf)$$

Where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the return for the market as a whole.

In this specification, the term (rm – rf) represents the market risk premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$[2] \quad \beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

Where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [2], is a measure of the covariance between the return on a specific security and the market, and reflects the extent to which the return on that security varies with a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

The CAPM approach is not without its shortcomings, and judgment is required to determine its inputs. The approach is sensitive to the method of calculating the risk premium (e.g., forward-looking or historical, geometric mean versus arithmetic mean, which security is selected for the risk-free interest rate, and whether adjustments to Beta are warranted.)

The theoretical premise of the model is also controversial, as it assumes that investors do in fact lower their risk by investing in diversified holdings. The model assumes all investors manage their portfolios in the most efficient manner in a well-functioning market and make investment decisions based on the impact on the portfolio, and not on a specific security in isolation. This assumption requires us to believe that investors focus only on the risk of the portfolio and not on the risk of holding a single stock.[43] Additionally, Betas for low-risk stocks, such as utilities, must be adjusted or predicted returns will otherwise be understated. Said another way, low Beta securities earn a higher return than the CAPM would predict, and high Beta stocks earn less than predicted.[44] These problems are exacerbated in the current market environment, where risk free rates remain near all-time lows but expectations call for steady increases over time. Similarly, market equity returns typically move in an inverse relationship with underlying bond yields, rendering historic risk premia unreliable in the current low bond yield environment.

b. Risk Free Rate

My CAPM analysis relies on the 2022 through 2024 average Consensus Economics forecast of the Canadian 10-year government bond (shown previously in Figure 9 and repeated below in Figure 18) and adds the historical spread between 10- and 30-year government debt. This period has been chosen to be forward looking, as required for an equity return. I have chosen a three year forecast of the Canadian bond yield to be conservative, even though I could have selected a longer forecast period (and therefore a higher bond yield) given the fact that the Board has typically reviewed the ROE for Liberty (and its predecessors) approximately every ten years.

[43] These statements are corroborated by the white paper, CAPM: an absurd model by Pablo Fernandez, Professor of Finance, IESE Business School, University of Navarra (October 6, 2014).

[44] Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc. (2006) at 73-74, includes the following discussion: "Because of the observed regressive tendency, a company's raw unadjusted beta is not the appropriate measure of market risk to use. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is adjusted beta;" *and* "[t]here is statistical justification for the use of adjusted betas as well. Statistically, betas are estimated with error. High-estimated betas will tend to have positive error (overestimated) and low-estimated betas will tend to have negative error (underestimated). Therefore, it is necessary to squash the estimated betas in toward 1.00. One way to accomplish this is by measuring the extent to which estimated betas tend to regress toward the mean over time. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. This adjustment which is commonly performed by investments services such as Value Line, Bloomberg, and Merrill Lynch, uses the formula: $\beta_{adjusted} = \alpha(\beta_{raw} - 1.0)$" Each firm gives 66% weight to the raw beta and approximately 34% to the market mean of 1.0, such that $\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw.}$

Figure 18: Forecast for 10-Year Government Bond Yields
2022 - 2024[45]

	2022	2023	2024	Average
Canada	1.60%	2.00%	2.40%	**2.00%**
U.S.	1.50%	1.80%	2.10%	**1.80%**

As illustrated in Figure 19, with an average spread between 10- and 30-year government bond yields of 57 basis points in Canada and 78 basis points for the U.S.,[46] the corresponding yields on 30-year government bonds over the period 2022-2024 are 2.57 percent for Canada and 2.58 percent for the U.S. As of February 26, 2021, the Canada and U.S. 30-year bond yields stood at 1.91 percent and 2.18 percent, respectively.

Figure 19: Risk Free Rate[47]

30-Year Risk Free Yield	**CDN$**	**U.S.$**
October 2020 Consensus Forecast Average 2022-2024 Forecasts 10-Year bond yield	2.00%	1.80%
Average Daily Spread between 10-year and 30-year government bonds (February 2021)	0.57%	0.78%
Average	**2.57%**	**2.58%**

Use of the 2022-2024 forecast, as opposed to the current risk-free rate, reflects the current market reality that near-term bond yields remain near all-time lows, and that investors factor higher interest rate levels into their forward-looking return expectations. Otherwise, the CAPM would not produce reliable results. The 30-year bond yield is appropriate to estimate

45 Consensus Forecasts by Consensus Economics Inc., Survey Date October 12, 2020, at 3 and 28.
46 Historical spreads were calculated using daily bond yields published on Bloomberg for the month of February 2021.
47 Consensus Economics Inc., Survey Date October 12, 2020; and Bloomberg for daily bond yields. Differences are due to rounding.

the expected equity return for Liberty as it best matches the risk-free instrument with the lives of utility assets on which the return depends.

c. Beta

The calculation of beta depends on the time period and the frequency of intervals for calculation of returns. Longer time periods generally produce more statistically significant beta results.[48] I have used betas published by Value Line and Bloomberg in my analysis. According to Value Line, the reported historical beta for each company is based on five years of weekly stock returns and uses the New York Stock Exchange as the market index.[49] I have set the Bloomberg parameters to compute betas with five years of weekly stock returns on the S&P 500 or S&P/TSX Composite, whichever is applicable, as the market. Both Value Line and Bloomberg betas are adjusted to compensate for the tendency of beta to revert towards the market mean of 1.0 over time. The betas used in my analyses are summarized below.

Figure 20: Beta

	Beta
Canadian Proxy Group	0.87
U.S. Gas Proxy Group	0.85
North American Proxy Group	0.86

d. Market Risk Premium

As the CAPM formula indicates, the market risk premium is a function of interest rates. That is, it is the return on the broad stock market less the risk-free interest rate. Generally, as can be observed in U.S. and Canadian data, the risk premium falls when interest rates rise, and

48 See, Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., First Printing (June 2006) at 71, "To enhance statistical significance, beta should be calculated with return data going as far back as possible. But the company's risk may have changed if the historical period is too long. Weighting the data for this tendency is one possible remedy, but this procedure presupposes some knowledge of how risk changed over time. A frequent compromise is to use a 5-year period with either weekly or monthly returns."

49 http://www.valueline.com/sup_glossb.html.

rises when interest rates fall. There is widely documented academic evidence of the inverse relationship between the market risk premium and interest rates.[50]

Estimates of the market equity risk premium generally fall into two camps: *ex-ante* (or forward looking) and *ex-post* (historical arithmetic average). An *ex-ante* approach may infer the market risk premium from DCF-derived or Bond Yield Risk Premium-derived ROE estimates by subtracting the risk-free rate and provides the current market view of stock returns in the current interest rate environment.

The *ex-post* market risk premium provides a longer view of the investment horizon and provides an estimate of how the market has performed over time. However, taken as an average, it is not sensitive to changes in interest rates and the prevailing economic environment. The *ex-post* market risk premium is typically calculated based on the arithmetic average of historical risk premia. Duff & Phelps calculates the historical risk premium for the U.S. from 1926-2020 as 7.25 percent, and the Canadian historical market risk premium from 1919-2020 as 5.54 percent (using Canadian dollars) and 5.90 percent (using U.S. dollars). The shortcoming of using a long-horizon historical equity risk premium is that it is slow to respond to the interest rate environment, so one would expect it to underestimate the risk premium in a low interest rate environment and overestimate the risk premium in a high interest rate environment. Said another way, the longer the averaging period, the less responsive the market risk premium will be to current market conditions.

My *ex-ante* risk premium is based on capital market conditions as of February 26, 2021, using forward projections of the return on the relevant market indices less the risk-free rate. For consistency, I have used a forecast of the 30-year bond yield in my calculation of the *ex-ante* risk premium. As shown in Exhibits JMC-5 and JMC-6, the forward return projections used in the computation of the forward-looking market risk premium were derived by calculating the implied market ROE on a market-capitalization-weighted basis for the individual companies in each broad market index (for the U.S., I have used the S&P 500 index; and for

[50] See e.g., S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. See also Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return, Financial Management, Spring 1986, at 66.

Canada, I have used the S&P/TSX Composite index). I have used the DCF methodology to determine the expected market return. This is the same methodology employed by FERC for estimating the forward-looking market return. Using this method, I have subtracted the forecasted risk-free rate from the expected market returns to arrive at the forward-looking equity risk premia results of 9.16 percent and 10.52 percent, respectively, for Canada and the U.S. In other words, today's stock markets are indicating these projected returns over the risk-free rate in valuations of the companies in these broad market indices.

Because the U.S. and Canadian economies are integrated and because capital flows freely across the border, the risk premiums for each country are highly correlated.

Accordingly, it is appropriate in markets that are more similar than not, and where there is no good reason to expect a divergence in market risk premiums, to derive a single forward-looking estimate. I have averaged both the Canadian and U.S. equity risk premiums to derive a combined North American equity risk premium. As shown in Figure 21, the combined market risk premium is 9.84 percent (using forward-looking return data) and 8.12 percent (using an average of forward-looking and historical returns).

Figure 21: Market Risk Premium Values

	Canadian MRP	U.S. MRP	Average
Historical MRP	5.54%	7.25%	6.40%
Forward-looking MRP	9.16%	10.52%	9.84%
Average	**8.12%**		

e. CAPM Results

The results of the CAPM analysis, including flotation costs, are provided in Figure 22 and are shown in detail in Exhibits JMC-4.1 and JMC-4.2.

Figure 22: CAPM Results (includes 50 bps flotation cost)

	Forward Looking MRP	Average of Historical and Forward Looking MRP
Canadian Proxy Group	11.61%	10.11%
U.S. Gas Proxy Group	11.44%	9.96%
North American Proxy Group	11.54%	10.05%

While I have presented the CAPM results using both a forward-looking MRP and an average of the historical and forward-looking MRP, I prefer the use of the forward-looking MRP under current market conditions because it better reflects the inverse relationship between interest rates and the market equity risk premium. Further, it is consistent with the method employed by the FERC[51], and takes into consideration the fact that government bond yields currently are well below the historical average level used to compute the historical MRP.

f. Flotation Costs

The adjustment for flotation costs compensates the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting, and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions. It is normal practice for Canadian regulators to allow an adjustment for flotation and financing flexibility. The Board has allowed such an adjustment to reflect the risks associated with equity issuance and financing flexibility. Consistent with this precedent, I have adjusted the CAPM and DCF results upwards by 50 basis points.

2. Discounted Cash Flow (DCF) Models

a. Approach

The DCF model evolves from the base premise that investors value a given investment according to the present value of its expected cash flows over time. It assumes that investors

[51] FERC Opinion No. 531-B, Order on Rehearing, issued March 3, 2015, at para 108-113.

will bid the lowest acceptable price for a share of the future earnings stream of a given company. A stock, identified by the investor as being high risk, will require a higher premium or higher return than would a lower risk investment. Investors will pay as much for a given share of stock as the next best alternative, that is, the next lowest risk-adjusted price. The required return is the equalizing factor that allows investors to compare investments of varying degrees of risk. The DCF model calculates the investors' required return by observing the price and dividend (earnings) stream of the stock. The model solves for the discount rate implied by the prevailing stock price by estimating future cash flows, as shown in Formula [3].

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad [3]$$

where:

P = the current stock price

g = the dividend growth rate

D_n = the dividend in year n

r = the cost of common equity

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE, as shown in Formula [4]:

$$r = \frac{D}{P} + g \quad [4]$$

Stated otherwise, the cost of common equity is equal to the dividend yield, plus the dividend growth rate.

The constant growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. Fortunately, these restrictions are less of a constraint when modeling utilities with predicable earnings and dividends.

One of the drawbacks of the DCF model is that it can be highly sensitive to growth rate estimates and anomalies in current stock prices. There are alternative forms of the DCF model that allow for changes in the growth rate assumption if there is reason to believe that investors do not expect a steady growth rate in perpetuity. The multi-stage form of the model sets the subject company's stock price equal to the present value of future cash flows received over several (typically three) "stages". In all three stages, cash flows are defined as projected dividends, which increase at the growth rate specific to each stage. The multi-stage growth model assumes that current growth rates are not constant, and over the long term, the company's growth will revert in perpetuity to the growth rate of the broader economy (usually GDP growth). I have presented results from both a Constant Growth DCF model and a Multi-Stage DCF model.

b. <u>Growth Rate Estimates</u>

Estimating investors' expectations of future growth for the proxy companies is a significant factor in the DCF model. Earnings and dividend growth result from the investment opportunities and strategies that a company pursues. Since the growth rate used in the DCF model is the estimate of future growth, there is no precise estimation methodology. Investors and analysts are aware of historical growth rates for a company and consider historical growth rates in their estimation of future growth rates. In considering the appropriate growth rate to use in the DCF model, the most relied upon indicators of investors' expectations are analysts' estimates of future earnings growth.

Analysts' earnings growth estimates are typically relied upon as an indicator of dividend growth rates for several reasons. First, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, to reduce the long-term growth rate to a single measure, as is the case in the constant growth DCF model, it is necessary to assume a constant payout ratio, and constant growth rates in earnings per share, dividends per share and book value per share. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings per share growth are widely available, whereas dividend and book value growth rate expectations are not generally estimated by analysts.[52]

Five-year earnings growth rates are publicly available from Zacks' Investment Research for U.S. companies. Yahoo! Finance, which is a public source for financial data from Thomson First Call, and SNL Financial, which is a subscription-based service, publish earnings growth rates for both Canadian and U.S. companies. All of these services provide consensus estimates that compile projections of earnings growth from several analysts. Value Line, which is a subscription-based publication, provides five-year projected earnings, dividend and book value growth rates based on the expectations of the individual analyst who has reviewed each company. Value Line covers all of the companies in the U.S proxy groups, and three of the six companies in the Canadian proxy group.

c. <u>Reliability of Analysts' Growth Rates</u>

The relationship between various growth rates and stock valuation metrics has been the subject of academic research.[53] Many published articles specifically support the use of analysts' earnings growth projections in the DCF model in general, as well as for a method of calculating the expected market risk premium in particular. A 1986 article entitled "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return" by Dr. Robert Harris, for example, demonstrated that financial analysts' earnings forecasts (referred to in the article as "FAF") in a Constant Growth DCF formula are an appropriate method of calculating the expected market risk premium.[54] In that regard, Dr. Harris noted that:

> …a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a

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52 Value Line Investment Survey is the only publication of which Concentric is aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

53 See, for example, Harris, Robert, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, <u>Financial Management</u>, Spring 1986.

54 Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return, <u>Financial Management</u>, 1986 at p. 66.

> consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[55]

Dr. Harris further noted that,

> Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[56]

In a subsequent article, Professors Carleton and Vander Weide performed a study to determine whether projected earnings growth rates are superior to historical measures of growth in the implementation of the DCF model.[57] Although the purpose of that study was to "investigate what growth expectation is embodied in the firm's current stock price,"[58] the authors clearly indicate the importance of earnings projections in the context of the DCF model. Professors Carleton and Vander Weide concluded that:

> …our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.[59]

Similarly, in an article entitled *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts".[60] In addition to other findings, Harris and Marston reported that,

> …in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[61]

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55 *Ibid*., at p. 59. Emphasis added. As noted in my Direct Testimony, Zacks and First Call, the sources of earnings growth projections that I use in addition to Value Line, are consensus forecasts.

56 *Ibid*., at p. 60.

57 James H. Vander Weide, Willard T. Carleton, Investor growth expectations: Analysts vs. history, The Journal of Portfolio Management, Spring, 1988.

58 *Ibid*., at p. 78.

59 *Ibid*., at p. 82.

60 Robert S. Harris, Felicia C. Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management, Summer 1992.

61 *Ibid*., at p. 63.

More recently (2004), the Carleton and Vander Weide study was updated to determine whether the finding that analysts' earnings growth forecasts are relevant in the stock valuation process still holds. The results of that updated study continued to demonstrate the importance of analysts' earnings forecasts, including the application of those forecasts to utility companies.[62] Similarly, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (1) analysts' forecasts are superior to forecasts based solely on time series data; and (2) investors do rely on analysts' forecasts."[63]

Optimism bias has been cited as a concern when using analyst growth rates. The concern is whether there is a tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. However, several regulatory changes have been implemented that were designed to provide fair disclosure and eliminate the possibility of analysts' bias.[64] By 2010, an article in the *Financial Analyst Journal* reported that analyst forecast bias had declined significantly

[62] Advanced Research Center, Investor Growth Expectations, Summer, 2004.

[63] The Risk Premium Approach to Measuring a Utility's Cost of Equity, Financial Management, Spring 1985.

[64] On August 15, 2000, the U.S. Securities and Exchange Commission ("SEC") adopted Regulation FD to address the selective disclosure of information by publicly traded companies and other issuers. Regulation FD provides that when an issuer discloses material non-public information to certain individuals or entities (generally, securities market professionals such as stock analysts or holders of the issuer's securities who may well trade on the basis of the information), the issuer must make public disclosure of that information. In this way, the new rule aims to promote full and fair disclosure. *Also*, in 2002 the SEC, the New York Stock Exchange ("NYSE"), the New York Attorney General ("NYAG"), and other state regulators introduced guidelines regarding the interaction between analysts and investment banks that has become known as the Global Settlement. The Global Settlement outlines several structural reforms that limit the interaction between analysts and investment banks, thus removing any incentive for analysts to produce upwardly biased growth forecasts. *And,* in Canada, regulators took a similar series of parallel actions to improve research independence and ensure the professional practice of Canadian securities analysts based on the report of the Canadian Securities Industry Committee on Analyst Standards, as well as the rules introduced during the Global Settlement in the U.S. The initiative was referred to as "Policy 11" with the purpose of "maintaining the integrity of the marketplace, by establishing requirements that reduce the potential for conflicts of interest and allow for the highest standards of ethical behavior." The initial draft of Policy 11 was issued on April 12, 2001 and became effective on February 1, 2004. Policy 11 required more disclosures from analysts and independence of research departments from investment banking departments with the issuance of 20 requirements and 9 guidelines that must be complied with where practicable.

or disappeared entirely as a result of regulatory changes implemented in the previous decade:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[65]

In addition, I also note that FERC in setting returns for electric transmission companies relies on short-term analyst growth rates in the DCF model, although it weighs the analyst growth rate by 80 percent and GDP (as an alternative measure of a long-term growth rate) by 20 percent. I also use GDP growth as a long-term growth rate in my Multi-State DCF model.

d. Dividend Yield

As shown in equation [5] below, the dividend yield component of the DCF model is calculated as follows:

$$[5] \qquad Y = \frac{D_0\,(1+0.5g)}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

For the DCF analysis, the dividend yields were calculated for each company in the Canadian and U.S. proxy groups by dividing the current annualized dividend by the average of the stock prices for each company. The price component of the calculation is based on the proxy

[65] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at p. 105.

companies' current annualized dividend and average closing prices for the 90-trading days ended February 26, 2021. Those dividend yields are multiplied by the DCF model factor (1 + 0.5g) to reflect expected future dividend increases, to arrive at the dividend yield component of the model.

e. Constant Growth Model

The constant growth DCF analysis for the Canadian and U.S. proxy groups is based on analysts' forecasts of earnings growth. This analysis recognizes that the consensus of analysts' EPS forecasts reflects the most important component of investors' growth rate expectations, and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company. As discussed previously, financial research and empirical literature indicate that analyst EPS forecasts are the best available estimates for future growth rates. Available earnings growth estimates were used from SNL Financial, Value Line, Zacks, and Yahoo! Finance for each company in the Canadian and U.S. proxy group. Those growth rates are shown on Exhibit JMC-7.

f. Multi-Stage Model

In order to address some of the limiting assumptions underlying the constant growth form of the DCF model, I also considered the results of a multi-period (three-stage) DCF model. The multi-stage DCF model tempers the assumption of constant growth in perpetuity in the constant growth DCF model with a three-stage approach: near-term, transitional, and long-term growth.

The multi-stage model transitions from near-term growth, (i.e., the average of Value Line, Zacks, SNL Financial, and Yahoo! Finance forecasts used in the constant growth model) for the first stage (years 1-5) of the analysis, to the long-term forecast of GDP growth for the third stage of the analysis (years 11 and beyond). The second, or transitional, stage connects the near-term growth with the long-term growth for the transitional period by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows at the same rate as GDP into perpetuity (or a total of 200 years in the model). The return on equity is the internal rate of return based on the stock price today and this stream of dividend payments.

I have applied the multi-stage DCF model to my three proxy groups. The assumptions used with respect to the various model inputs are described in Figure 23.

Figure 23: Multi-stage DCF Model Assumptions

Model Input		Stage 1	Stage 2	Stage 3
Years	Start	1 – 5	6 – 10	>11
Stock Price and Dividend Yields	90-day average			
Earnings Growth		EPS growth as average of Value Line, First Call, SNL and Zacks projected growth rates	Transition to Long-term GDP growth on arithmetic average basis	Long-term GDP Growth

The nominal GDP growth rates for all proxy groups (used in Stage 3) were developed using available data for each country from Consensus Economics, Inc. for the forecast period furthest in the future (2026-2030). These forecasts reflect real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (including inflation) GDP growth rate.[66] The estimates of nominal GDP growth that were utilized are summarized in Figure 24:

Figure 24: Estimates of Nominal GDP Growth

Source	**Canada**	**U.S.**
Real GDP Growth	1.80%	2.00%
Inflation	2.00%	2.10%
Nominal GDP Growth	**3.84%**	**4.14%**

The Multi-Stage DCF results are shown in Exhibit JMC-8.

g. DCF Results

[66] Consensus Forecasts, for 2026-2030, October 12, 2020, at 3 and 28, Calculated as: [Real GDP x (1+CPI)+CPI]

As shown in Figure 25, the DCF analyses for both methods indicate an average cost of common equity of 11.11 percent for the Canadian proxy group, 9.28 percent for the U.S. gas proxy group, and 10.38 percent for the North American proxy group, including a 50 basis point adjustment for flotation costs.

Figure 25: Mean DCF Results (including 50 bps flotation costs)

Proxy Group	Constant Growth	Multi-Stage	Average
Canadian Proxy Group	11.47%	10.74%	**11.11%**
U.S. Gas Proxy Group	9.58%	8.97%	**9.28%**
North American Proxy Group	10.72%	10.04%	**10.38%**
Average	**10.59%**	**9.92%**	**10.26%**

3. Risk Premium Model

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

ROE = RP + Y [5]

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking, estimates of the cost of equity and others that consider historical, or *ex-post*, estimates. For my Risk Premium analysis, I have relied on authorized returns from a large sample of U.S. gas distribution companies. It is necessary to conduct the Risk Premium analysis based on authorized returns for U.S. gas distribution companies because there are not a sufficient number of Canadian ROE decisions to develop a statistically-meaningful regression analysis.

To estimate the relationship between risk premia and interest rates, I conducted a regression analysis using the following equation:

$RP = a + (b \times Y)$ [6]

where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);

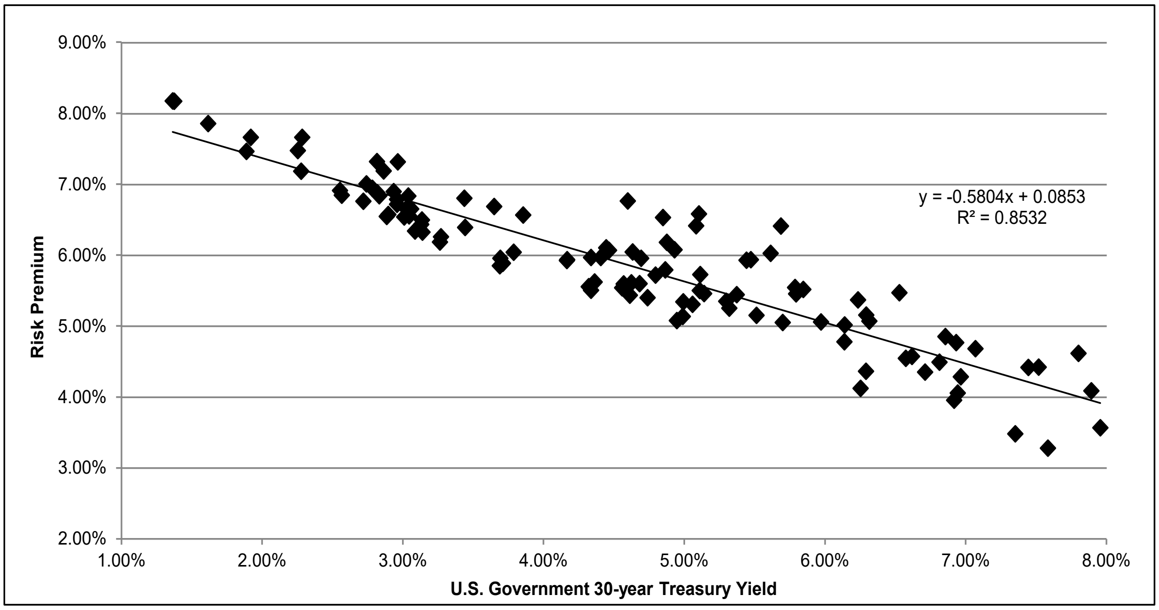
a = Intercept term;

b = Slope term; and

Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from 677 gas distribution company rate cases in the U.S. from January 1992 through February 26, 2021, as reported by Regulatory Research Associates.

Figure 26: Risk Premium Results



As illustrated by Figure 26, the risk premium varies with the level of bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, I consider three estimates of the 30-year Treasury yield, including the current 30-day average, a near-term Blue Chip consensus forecast for Q2 2021 – Q2 2022, and a Blue Chip consensus forecast for 2022–2026. I find this 5-year result to be most applicable for the following reasons: (1) investors are expecting increases in government bond yields; and (2) investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibit JMC-9, which allow for the estimation of the risk premium at varying bond yields, the results of my Risk Premium analysis are shown in Figure 27.

Figure 27: Risk Premium Results Using 30-Year Treasury Yield

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q2 2021–Q2 2022 Forecast for Yield on 30-Year Treasury Bond[67]	Using 2022-2026 Forecast for Yield 30-Year Treasury Bond[68]
Yield	1.97%	2.28%	2.80%
Risk Premium	7.39%	7.21%	6.91%
Resulting ROE	9.36%	9.49%	9.71%

VII. BUSINESS AND FINANCIAL RISK ASSESSMENT

A. Overview

In this section, I examine Liberty's risk profile in 2020 as compared to 2010, when the Board last established the cost of capital for Liberty, and relative to the companies in my Canadian and U.S. peer groups. In the 2010 decision, the Board determined that a risk adjustment of 275 basis points to the return for a benchmark utility was appropriate to compensate investors for the higher business and financial risk of EGNB. When added to the return for a benchmark utility of 8.13 percent, and including 50 bps for flotation costs, this brought the authorized return for EGNB to 10.9 percent, which represented a 210 basis point reduction in the authorized return of 13.0 percent that was established by the Board in 2000.

The risk for any company, including utilities, has two principal sources: business risk and financial risk. Business risk is the risk inherent in the company's operations, irrespective of how the company is financed. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These risks also have a time dimension. For a utility, short-term risks are those that will reverse or resolve themselves within a year or two, either through regulatory relief or the normal ebb and flow of earnings. Examples include earnings

[67] Blue Chip Financial Forecasts, Vol. 40, No. 3, March 1, 2021, at 2
[68] Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14.

loss due to weather or losses that typically receive deferral account treatment or that would otherwise be included in a subsequent years' cost of service. Long-term risks represent an actual shift in the business risk profile of the company for which there is no foreseeable mitigation. Examples of long-term risks include: a sustained depressed business environment or changes in regulatory or environmental policies that impact the profitability of a company's operations.

Both short-term and long-term risks impact the utility business risk profile and are considered by investors. Investors will demand greater compensation for what they perceive to be higher risk. That risk can generally be boiled down to whether the investor will actually be able to recover their investment plus earn the allowed return on invested capital, and whether they have been afforded a reasonable opportunity to earn the allowed return by the regulator.

I begin my business risk analysis with a discussion of the local economic conditions and the outlook for New Brunswick.

B. New Brunswick Economic Conditions and Outlook

According to the Conference Board of Canada, New Brunswick's GDP is expected to decline by 5.2 percent in 2020, which is less than the projected decline of 6.6 percent for all of Canada. The Conference Board attributes this milder recession in New Brunswick to the fact that the province has not been affected as much by the COVID-19 pandemic as many other provinces. In addition, public sector workers account for a higher share of overall workers in New Brunswick, which has tended to mitigate the effect of previous economic downturns in the province. In October 2020, employment in the province was 2.3 percent lower than February 2020 levels as compared to a 3.3 percent decline in employment for Canada overall. Nevertheless, the economy in New Brunswick has been negatively affected by stricter lockdown measures in Europe and the remainder of Canada, which are key markets for New Brunswick's exports. The Conference Board expects the manufacturing industry in New Brunswick to contract by 7.5 percent in 2020 due mostly to a big drop in activity at the Irving Oil refinery in Saint John. Home prices in New Brunswick have increased by a healthy margin, driven by a growing population base and very low mortgage rates. However, new housing starts are expected to cool in the fourth quarter and taper off over the medium term as net provincial migration returns to negative territory.[69]

TD Economics reports that New Brunswick's success in containing the pandemic has set the province up for a relatively shallow economic hit in 2020. With the exception of some of its Atlantic Canada peers, the province has maintained the lowest per capita caseload in all of North America. Notwithstanding this relative outperformance, however, the second wave of the virus has not left the province unscathed. TD Economics notes that the second wave spelled the end of the "Atlantic Bubble," which had mitigated the economic impact of COVID-19 on the provincial economy, including many travel and hospitality industries in Atlantic Canada. TD Economics is forecasting that the unemployment rate is expected to improve from 9.8 percent in 2020 to 8.6 percent in 2021, and that nominal GDP is expected to increase by 5.3 percent in 2021 as compared to a 2.2 percent decline in 2020. They caution, however, that executing on the commitments at the federal and provincial levels to ramp up the pace of international immigration will be important to counter New Brunswick's aging demographics and support its economy.[70]

In summary, while economic conditions in New Brunswick have been relatively stronger during the pandemic than many provinces in Canada, there are longer term structural challenges associated with an aging population and declining workforce.

C. Small Size

Liberty is substantially smaller than the vast majority of other gas distribution utilities in Canada and the U.S. The small size of Liberty relative to the proxy group companies is an important risk factor in determining Liberty's cost of equity. Academic literature recognizes that smaller companies tend to be rewarded with higher total returns than larger companies, even after the relative illiquidity of smaller company stock is taken into account. As previously noted, Liberty has approximately 12,000 gas distribution customers. Figure 28

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[69] The Conference Board of Canada, Provincial Outlook, "Tough Times Ahead," November 25, 2020, at 11-12.

[70] TD Economics, "Provincial Economic Forecast, It's Always Darkest Before the Dawn," December 15, 2020, at 8.

compares the number of customers for Liberty to the total gas distribution customers for the North American proxy group companies in 2019.

Figure 28: Number of Gas Customers for Liberty and Proxy Group

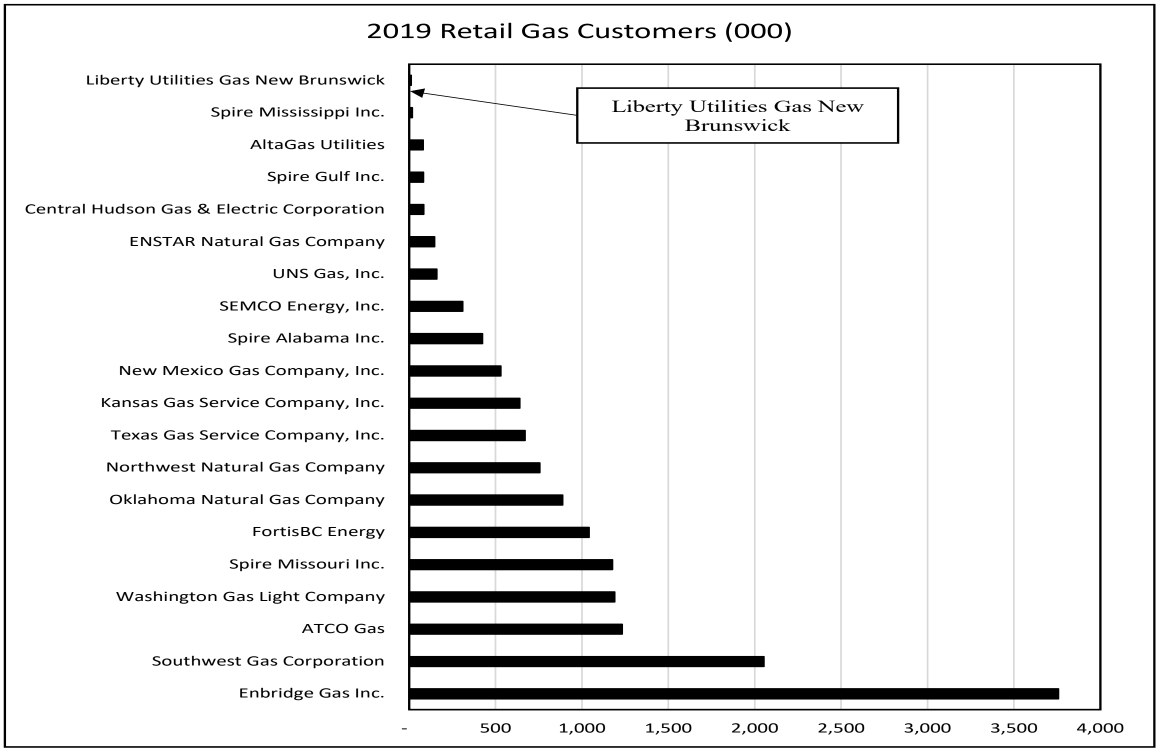
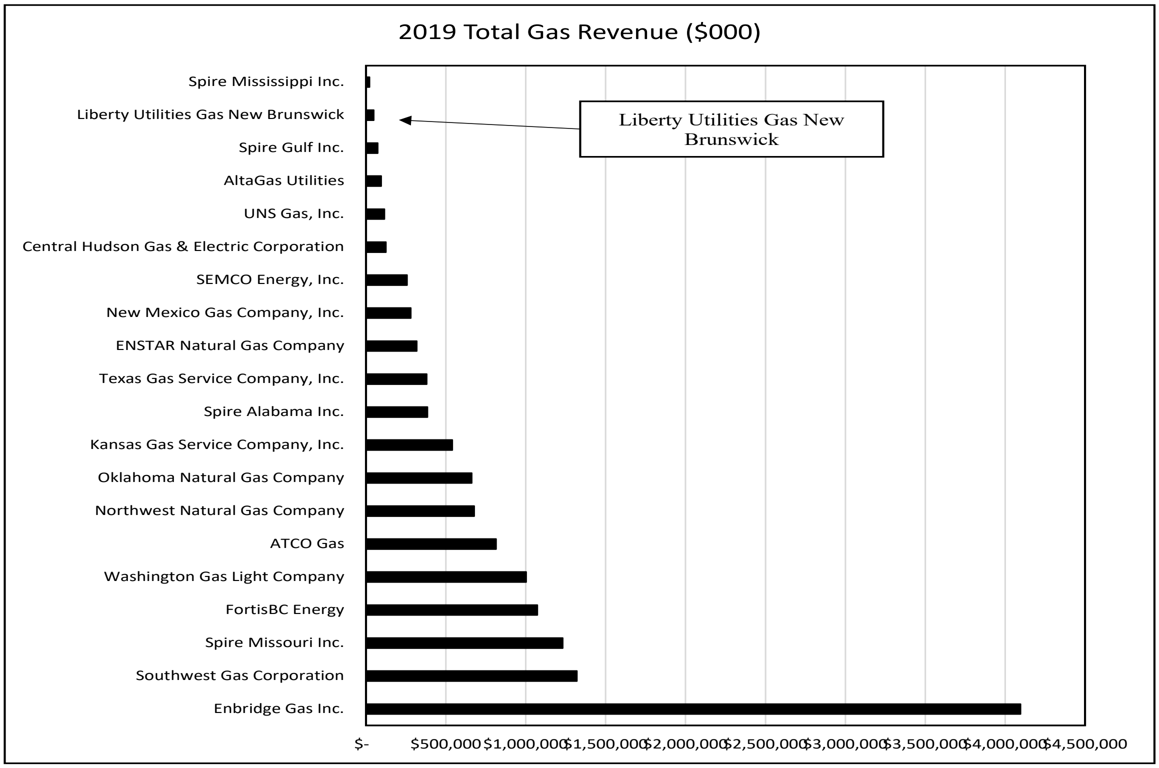


Figure 29 compares Liberty's revenues to the gas distribution revenues of the operating subsidiaries of the North American proxy group companies. As shown in that Figure, Liberty's 2019 revenues were US $39.5 million, compared with the proxy group median revenues of approximately US $384 million.

Figure 29: 2019 Gas Distribution Revenues of Liberty vs. Proxy Group



Liberty's small size relative to the proxy group companies means that Liberty's earnings and cash flows may be disproportionately affected by events such as the loss of its larger customers, weaker than expected demand for gas distribution service due to general macroeconomic conditions in the service territory, or fuel price volatility. Liberty's risk profile is highly unusual given New Brunswick's Single End Use Franchise bypass customers, which consume as much as 80 percent of the natural gas used in New Brunswick, yet pay minimal revenue to Liberty. I am not aware of any other North American gas utility with a similar profile. So smaller changes in volume for Liberty's customers have a magnified impact on its revenues and earnings compared to utilities serving larger loads and a broader customer base. To my knowledge, no other company in the Canadian or U.S. proxy groups faces a similar situation. Similarly, capital expenditures for non-revenue producing investments such as system maintenance and replacements will put proportionately greater pressure on customer costs. Taken together, these risks affect the return required by investors for smaller companies. Liberty is relatively small as compared to the proxy group companies used for the ROE analysis. This small size magnifies the effect of other business and financial risks on Liberty.

Credit rating agencies consider small size as a distinguishing risk factor. Moody's, for example, considers the size and diversity of utility operations to be a distinguishing factor that makes some utilities riskier than others. In discussing its rating methodology for regulated electric and gas utilities, Moody's states:

> 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 economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.[71]

Liberty's service territory is characterized by the small size and lack of geographic and economic diversity that Moody's describes as an increased risk factor for regulated utilities. In particular, Liberty's customers are spread across a large geographic area, meaning that Liberty's ratio of customers per kilometer of pipe is lower than distribution companies that operate in more densely populated areas such as Montreal, Toronto, or Vancouver.

Further, Morningstar/DBRS has commented specifically on the risk associated with the small size of Liberty as follows:

> LUNB has approximately 12,000 customers as at the end of 2020, and the population in the Company's service areas has not experienced any meaningful increase over the past 10 years. This unusually small customer base makes it very difficult for LUNB to recover capex (if a substantial amount is required) over a reasonable period of time.[72]

My conclusion is that Liberty is significantly smaller than the proxy group companies and that investors would require a substantial risk premium in relationship to the larger and more diversified proxy group companies.

71 Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 19.
72 Morningstar/DBRS, Liberty Utilities (Canada) LP, March 17, 2021, at 4.

D. Business Risks for Liberty

The Board's 2010 decision considered five areas of business risk for Liberty, including Market risk; Competitive risk; Supply risk; Regulatory risk; and Deferral Account risk. I have considered those same five fundamental risk factors in my risk assessment, both in terms of how Liberty's risk has changed from 2010 to 2020 and how Liberty's risk compares to that of the proxy group companies in Canada and the U.S. The first three risk factors are addressed in more detail in Liberty's evidence, on which I rely in drawing the following conclusions:

1) Market risk: Liberty has greater market risk than in 2010. Some factors have not changed such as the relatively low population and low urban saturation, low industrial load and high electric space heating saturation. Market risks that have worsened include the proliferation of new technologies such as heat pumps as well as the political trend and landscape promoting electrification, carbon fuel bans and climate action initiatives. Evidencing these trends, Liberty has not added as many customers as forecast.

2) Competitive risk: Liberty has greater competitive risk than in 2010. The relative differential between natural gas and electricity prices has been lower than anticipated, and continues to be lower than most other provinces. The competitive advantage for electricity has also been significantly altered since 2010 due to the popularity and efficiencies of heat pump appliances. Additionally, since 2015 the propane environment created by additional supply and storage facilities in Atlantic Canada has resulted in a market shift from a marginalized energy option to a relevant option and competitor due to the significant changes in pricing.

3) Supply risk: Liberty's supply risk has moderated to some degree because natural gas supply is being provided from more stable markets resulting in more stable pricing and lower overall prices than in 2010.

1. **Regulatory risk**

Liberty files an annual rate application with the Board that includes most costs and expenses with the exception of the cost of capital, which has not been reviewed since 2010. Liberty has two significant deferral accounts, which total $210 million, the cost of which is being borne by a small customer base. These two deferral accounts add about $12 million per year to Liberty's revenue requirement. The balance in the Development O&M account is $78 million, which is being amortized over 40 years, while the balance in the Regulatory deferral account is $96 million, amortized over 26 years, plus a variable portion of approximately $36.1 million, which is reduced through an over-earnings sharing mechanism. The Development O&M account is included in rate base and earns the weighted average cost of capital. The Regulatory deferral account is not in rate base and does not earn a return; further, recovery of the variable portion of $36.1 million remains at risk.

In addition, Liberty does not have a revenue decoupling mechanism or a weather normalization clause. Therefore, Liberty's revenues and cash flow tend to fluctuate from month to month due to the effects of abnormal weather and/or weak economic conditions on the demand for natural gas.

My conclusion is that Liberty's regulatory risk has not changed materially since 2010, but as discussed in the following section, Liberty has higher regulatory risk than many companies in the North American proxy group due to the absence of protection against volumetric risk, which is common for gas distributors, and due to the limited number of regulatory mechanisms that are in place to mitigate certain other risks.

2. Deferral account risk and political interference

This was the most important risk factor for Liberty in 2010. In 2012, the government unilaterally changed the franchise agreement with what was then EGNB. EGNB ultimately reached a settlement agreement in 2016 that reduced the balance in the deferral account from $278 million to $144.5 million, with EGNB writing off the difference. Since that time, Liberty has had more stability and certainty with regard to the deferral account. The 2016 settlement agreement with the government also included a 25-year extension of the franchise agreement starting in 2019. Liberty believes that the risk of government interference has been reduced; however, that can obviously change at any time, as was shown in 2012. Political risk remains a concern for the investment community, as Morningstar/DBRS noted in a recent report on Liberty Utilities (Canada): "However, potential government intervention in the future remains a concern because the Province does not yet have a long history of regulatory stability."[73] DBRS further elaborated on this concern as follows:

> Although the regulatory framework in NB improved significantly in 2016 compared with prior years and has been stable since, DBRS Morningstar is of the opinion that there is no assurance that the Government of New Brunswick will not intervene again in the future with adverse legislation that could have a material negative impact on the Company's credit risk profile.[74]

My conclusion is that Liberty has lower absolute deferral account risk than in 2010 because the issues around the large deferral account balance were settled in 2016. In addition, the franchise agreement for Liberty has been renewed through 2044. While political risk is currently dormant, history suggests that the provincial government is willing to step in and change agreements that govern the operations of Liberty. Investors are aware of this history and the potential for political risk and would be expected to factor that into consideration in evaluating Liberty's risk profile and setting their return requirements. It is also the case that no other company in the proxy group has the financial burden of the two large deferral accounts that reflect early stage growing pains, indicating that Liberty has greater relative risk.

E. Liberty No Longer in Development Period

In 2000 the Board approved the concept of the development period, which represented a startup period for a new utility during which time it is not expected to operate in a mature manner while its infrastructure and customer base are being developed. At the time, all rates were determined on a market-based method, which generally meant that revenues were below the utility's costs. Revenue shortfalls were added to a regulatory deferral account. By contrast, for a mature utility, rates are usually set on a cost of service basis.

In the 2016 decision, the Board determined that from a "practical perspective" EGNB was no longer in the development period because the utility had modified its business strategy from significant expansion of plant, customers and load, to a strategy with minimal investment and cash generation. The Board indicated that the utility's efforts are now focused on avoiding

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73 Morningstar/DBRS, Liberty Utilities (Canada) LP, March 17, 2021, at 2.
74 Ibid, at 4.

the loss of existing customers to new competitive threats, rather than developing new customers. However, despite finding that the development period was over from a "practical perspective," the Board agreed with the experts that the potential impact of regulation created the potential for the inability of the Board to establish rates that allow Liberty the recovery of its full approved revenue requirement. As a result, the Board determined that Liberty remained in the development period until the end of the general franchise agreement, which expired in 2019. Prior to the expiration of the development period, Liberty moved from market-based pricing to cost-based pricing (although cross-customer subsidies remain). Under development period pricing, Liberty had the possibility of recouping under-recovered revenues through the deferral mechanism. Under cost-based rates, Liberty has no such recourse. It therefore has less flexibility to compete against alternative fuels. On balance, this places the company at greater risk as it has one less tool to accelerate growth in its customer base and scale up its operations.

F. Conclusions on Changes in Liberty's Business Risk Profile

In summary, Liberty's gas supply risk has moderated since 2010 as lower and more stable natural gas prices have offset the risk of procuring natural gas from Ontario and Western Canada. Liberty's market risk and competitive risk have increased since 2010, as reflected by the smaller than anticipated customer additions, due to the fact that the differential between natural gas and electricity prices has made fuel conversion less attractive to customers, especially those with electric heating. From an investor's perspective, Liberty's regulatory risk has increased since 2010 with the government action in 2012 to amend the franchise agreement and partial write-off of Enbridge's initial investment in the system. I am not aware of any other gas distribution company in North America that has experienced a write-down of this relative magnitude. Since then, the regulatory environment in New Brunswick has generally been constructive and supportive of Liberty's credit profile. However, Liberty's small size continues to make it significantly riskier than other larger investor-owned gas utilities in Canada and the U.S. Even though it was determined in 2016 that Liberty is no longer in the development period, Liberty has not yet achieved the increased scale that was expected a decade ago and customer growth has stagnated in recent years. The risk associated with political interference remains an ongoing risk for investors.

These risks distinguish Liberty from other investor-owned gas utilities operating in most other North American regulatory jurisdictions.

G. Relative Risks of Liberty to Other Gas LDCs in Canada

In this section, I compare the risk profile of Liberty to other investor-owned gas distribution companies in Canada. In particular, I focus on the relative size of the companies as measured by number of customers, throughput, and revenues. I also highlight any important factors that affect the regulatory risk of these companies, such as mechanisms that protect against volumetric risk or regulatory lag.

I begin, in Figure 30, with a comparison of authorized ROEs for other Canadian investor-owned gas distribution companies.

Figure 30: Comparison of Authorized Equity Returns

Operating Utility	Equity Return
Liberty Gas New Brunswick (existing)	10.90%
Liberty Gas New Brunswick (proposed)	11.50%
AltaGas Utilities, Inc.	8.50%
ATCO Gas	8.50%
Enbridge Gas[75]	8.34%
FortisBC Energy	8.75%
Gaz Metro LP	8.90%
Gazifere Inc.	9.10%
Heritage Gas Limited	11.00%
Pacific Northern Gas Ltd.	9.50%
Pacific Northern Gas Ltd. (Fort St. John/Dawson Creek)	9.25%
Pacific Northern Gas Ltd. (Tumbler Ridge)	9.50%
Canadian Gas Average	9.13%
Canadian Gas Median	9.00%
US Gas LDC Average (2019/2020)	9.58%
US Gas LDC Median (2019/2020)	9.60%

[75] Enbridge Gas Distribution and Union Gas Ltd. were combined in January 2019 to form Enbridge Gas.

As shown in Figure 30, the average authorized returns for other Canadian gas distribution companies range from 8.34 percent (the Ontario formula return) to 11.0 percent for Heritage Gas in Nova Scotia, with an average of 9.13 percent. These returns are well above the return for a benchmark distribution utility of 8.13 percent that was set by the Board in 2010.[76] The average authorized return for gas distributors in the U.S. is higher at 9.58 percent in 2019 and 2020. These authorized equity returns serve as a benchmark that investors consider in setting their return requirements for gas distribution companies. This evidence demonstrates that the return requirements for a benchmark utility are higher than what was approved by the Board in 2010. In addition, as discussed in the following section, Liberty has greater business and financial risk than other gas distribution companies in Canada, which supports a risk adjustment to the average return for a benchmark distribution utility. In particular, Liberty has higher risk due to its small size (both in terms of customers and throughput), the absence of deferral and variance accounts which are common for other gas distributors in Canada and the U.S., and the fact that the other gas distributors except for Heritage Gas Limited ("Heritage Gas") have provided service to customers for many decades Figure 31 summarizes several key points of comparison, which are discussed in more detail following the table.

[76] Decision in the Matter of a Review of the Cost of Capital for Enbridge Gas New Brunswick L.P., November 30, 2010

Figure 31: Risk Comparison of Canadian Gas LDCs[77]

Company	2019 Customers	2019 Annual Throughput (000 GJs)	2019 Annual Revenues C$ (millions)
Liberty Utilities Gas New Brunswick	12,000	5,575	$49.3
Heritage Gas Ltd	7,700	10,100	$121.3
Pacific Northern Gas Ltd	42,000	10,159	$264.2
Gazifere	43,500	7,000	$228.4
Energir (formerly Gaz Metro)	207,000	238,700	$1,561.9
FortisBC Energy	1,041,000	227,000	$1,331.0
ATCO Gas	1,232,400	270,505	$824.1
AltaGas Utilities	80,700	20,686	$117.2
Enbridge Gas	3,755,000	516,999	$5,084

Heritage Gas is most comparable to Liberty in Canada. In 2003, Heritage Gas was granted a 25 year franchise agreement to provide natural gas distribution service in Nova Scotia, a province that did not previously have natural gas. Like Liberty, Heritage Gas is a greenfield gas distribution company. At year-end 2019, Heritage Gas had approximately 7,700 customers (7,200 residential and 500 commercial), rate base of $313 million, annual

[77] Source: Customer data for Heritage Gas Ltd from company website; revenue data from 2019 Financial Compliance Filing with Nova Scotia Utility and Review Board, and throughput data from Black and Veatch Rate Class Survey for Liberty. Revenue data for Pacific Northern Gas Ltd. and Gazifere from Dun & Bradstreet. Customer and throughput data from Black and Veatch Rate Class Survey. Revenue data for Energir from 2019 annual report, at 97, throughput data at 19, and customer data from 2019 MD&A, at 6. Data for FortisBC Energy from Fortis 2019 annual report, at 27, and customer data at 17. Data for ATCO Gas and AltaGas Utilities from Rule 005 filings with Alberta Utilities Commission. Data for Enbridge Gas from 2019 Annual Report and 2019 Consolidated Financial Statements.

revenues of $121 million (approximately 2.5 times larger than Liberty) and annual customer growth of approximately five percent. There are approximately 21,400 potential customers with access to the Heritage Gas system. Natural gas has been adopted by all major hospitals and universities in Halifax, as well as many schools and businesses. Heritage Gas has an authorized ROE of 11.0 percent and a deemed common equity ratio of 45.0 percent, both of which were established in a November 2011 decision.

Pacific Northern Gas-West (PNG-West) serves approximately 42,000 gas distribution customers (3.5 times larger than Liberty) in British Columbia. PNG-West's annual throughput is 1.8 times larger than Liberty's, and its annual revenues are approximately 5.4 times greater than Liberty's, at $264 million. The British Columbia Utilities Commission ("BCUC") determined in the 2016 GCOC Stage 2 proceeding that PNG-West had higher risk than the benchmark utility with respect to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012).[78] Liberty has also experienced issues related to slower than expected customer growth and declining average use per customer over the past decade. PNG-West's authorized ROE of 9.50 percent is based on a risk premium above the benchmark utility in British Columbia, which is FortisBC Energy. PNG-West was awarded a risk premium of 75 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding.[79] PNG-West has 46.5 percent deemed common equity, as compared to Liberty's 45 percent common equity ratio.

In Quebec, Gazifere provides gas distribution service to approximately 43,500 customers (3.6 times larger than Liberty) has annual throughput that is 1.26 times greater than Liberty's and annual revenues that are 4.6 times larger than Liberty, at $228 million. Gazifere has an authorized ROE of 9.10 percent and a deemed common equity ratio of 40.0 percent. Energir (formerly Gaz Metro) provides gas distribution service to slightly more than 200,000 customers, including Montreal. Energir's annual gas distribution revenue in Quebec is approximately 32 times greater than Liberty's, at slightly more than $1.56 billion. Energir has an authorized ROE of 8.90 percent and a deemed common equity ratio of 38.5 percent.

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78 Ibid, at 102.
79 BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014, at 113.

In addition, Energir has 7.5 percent preferred stock in its capital structure, meaning that its long-term debt represents 54.0 percent of the total capital structure for Gaz Metro.

In British Columbia, the benchmark utility is FortisBC Energy, which is substantially larger than Liberty, both in terms of retail customers served and regulated revenues. FortisBC Energy serves slightly over one million gas distribution customers (87 times larger than Liberty) and has annual revenues of $1.33 billion (27 times higher than Liberty). FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than Liberty. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity.

In Alberta, ATCO Gas provides gas distribution service to over 1.2 million customers and has annual revenues of $824 million (17 times larger than Liberty). ATCO Gas has an authorized ROE of 8.50 percent, based on the generic ROE in Alberta, and a deemed equity ratio of 37.0 percent. AltaGas Utilities provides gas distribution service to approximately 80,700 customers (6.7 times larger than Liberty) and annual revenues of $117 million (2.4 times greater than Liberty). AltaGas Utilities has an authorized ROE of 8.50 percent, based on the generic ROE in Alberta, and a deemed equity ratio of 39.0 percent. In Ontario, gas distribution service is provided by Enbridge Gas, which serves almost 3.8 million customers and has annual revenues of slightly more than $5.0 billion (103 times larger than Liberty). Enbridge Gas has an authorized ROE of 8.34 percent (set by the OEB's annual formula) and a deemed common equity ratio of 36.0 percent.

H. Relative Risk of Liberty and North American Proxy Group

The purpose of the proxy group risk analysis is to both select companies for cost of equity analysis and to determine whether any adjustments should be made to account for differences in business and financial risk between the proxy groups and Liberty. Because the number of companies in the Canadian proxy group is limited, it is necessary to look beyond Canada to incorporate a U.S. sample of low-risk gas distribution utilities in a North American proxy group. To evaluate the comparability of these companies, I have examined the business and financial risks of those companies relative to those of Liberty.

The North American proxy group is screened for U.S. holding companies comprised primarily of regulated gas distribution utilities. The resulting group of North American regulated utilities has a risk profile similar to that of a benchmark utility. As shown in Exhibit JMC-10, all proxy group companies operate in exclusive service territories, with slightly more than half (52 percent) of the operating utilities held by the proxy group setting rates based on a forecast or partially forecast test year. The North American proxy group operating companies have an average credit rating of A-, as compared with BBB for Liberty.

Like Liberty, the North American proxy group utilities have no exposure to commodity price risk or supply risk due to the prevalence of fuel pass-through mechanisms. Further, North American utilities are increasingly protected from market (or demand) risk by full or partial decoupling mechanisms, with 66 percent of the proxy group operating companies protected to some extent by such mechanisms. Regulatory lag is mitigated by the use of generic infrastructure riders, capital trackers, and deferral accounts which are employed by the vast majority of the proxy group. For example, 64 percent of the operating companies in the proxy group have generic infrastructure riders, and 52 percent have a deferral account or other mechanism to recover costs associated with conservation program expenses.

Liberty is closely aligned with the North American proxy group in terms of test year convention and commodity price risk. However, Liberty has greater volumetric risk than the North American proxy group due to an absence of either revenue decoupling or weather normalization mechanisms that mitigate the effect of changes in demand on Liberty's revenues and cash flows. In addition, Liberty has many fewer cost recovery mechanisms such as riders and capital trackers than the North American proxy group. This elevated business risk places Liberty's risk profile well above that of my average proxy group companies. I consider these risk differences in combination with financial risks in recommending an equity ratio for Liberty.

Based on my research and analysis, an ROE toward the upper end of the range for the proxy group is appropriate for a company of Liberty's risk profile. Considering the range of results, the low end of the estimates are for the U.S. proxy group, and the upper end estimates are for the Canadian proxy group. I believe the upper end average is warranted. This reflects a risk differential of 160 basis points over the lower end benchmark set by the U.S. proxy group results. This implicit risk adjustment derived from the proxy group differential is 115 basis points lower than the explicit risk adjustment of 275 basis points that was authorized by the Board in 2010. A reduction in the risk adjustment is reasonable given the fact that Liberty no longer has a large balance in two deferral accounts and given the Board's determination that Liberty is no longer in the development period. However, some risk differential remains appropriate due to the very small size and other business and operating risks of Liberty relative to other gas distribution companies in Canada, including competitive risk, market risk, and regulatory/political risk. As discussed previously, Heritage Gas, which is the most similar comparator to Liberty in Canada. has an authorized ROE of 11.0 percent and a deemed common equity ratio of 45.0 percent.

I. Financial Risks for Liberty

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 which 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 during the ongoing COVID-19 pandemic that began to affect financial markets in February 2020.

The equity component in the capital structure, besides providing a return that compensates shareholders for their investment, serves to buffer unanticipated earnings swings. If the equity layer becomes too thin, lenders will be concerned that the company may not be able to meet its fixed debt obligations and will require a higher yield to compensate for the additional risk. Additionally, as the equity layer is reduced, earnings are also reduced such that an unexpected earnings disruption has a greater impact on the thinner equity layer. Shareholders require a higher return to compensate for this increased risk to their investment return. Accordingly, an appropriate equity ratio benefits both shareholders and customers by reducing overall financing costs.

In the 2010 decision, the Board set Liberty's deemed equity ratio at 45.0 percent. This represented a five percent reduction in the deemed equity ratio of 50.0 percent that was established by the Board in 2000.

1. Comparison to Capital Structure of Other Canadian and U.S. Gas Distributors

As explained in Section IV, I have selected three proxy groups consisting of Canadian, U.S., and North American utilities for purposes of establishing my ROE recommendation for Liberty. In order to assess the reasonableness of the common equity ratio for Liberty, my analysis is based on a comparison to the equity ratios of other investor-owned gas distributors in Canada and the U.S. at the operating company level because that is the level at which a regulated capital structure is established based on an evaluation of the business risk of the utility and related factors.

As shown in Figure 32, Liberty's deemed common equity ratio of 45.0 percent is higher than eight of the eleven other Canadian investor-owned gas distribution operating utilities. The median authorized common equity ratio for the operating companies in the U.S. Gas proxy group is 52.0 percent, which is approximately 7.0 percentage points higher than Liberty's current deemed common equity ratio of 45.0 percent.

Figure 32: Comparison of Deemed Equity Ratios

Operating Utility	Deemed Equity Ratio
Liberty Gas New Brunswick (existing)	45.0%
Liberty Gas New Brunswick (proposed)	50.0%
AltaGas Utilities, Inc.	39.0%
ATCO Gas	37.0%
Enbridge Gas	36.0%
Energir (formerly Gaz Metro)[80]	38.5%
FortisBC Energy	38.5%
Gazifere Inc.[81]	40.0%
Heritage Gas Limited	45.0%
Pacific Northern Gas Ltd.	46.5%
Pacific Northern Gas Ltd. (Fort St. John/Dawson Creek)	41.0%
Pacific Northern Gas Ltd. (Tumbler Ridge)	46.5%
Canadian Gas Average	**40.8%**
Canadian Gas Median	**39.0%**
US Gas LDC Average (2019/2020)	**52.5%**
US Gas LDC Median (2019/2020)	**52.0%**

It is reasonable for Liberty to have an above average deemed equity ratio given the small size and other business risks of Liberty as compared to the Canadian gas distribution companies listed in Figure 32. Liberty's deemed equity ratio of 45.0 percent is consistent with the equity thickness that has been authorized for other smaller gas LDCs including Heritage Gas at 45.0 percent, Pacific Northern Gas at 46.5 percent, and Pacific Northern Gas (Tumbler Ridge) at 46.5 percent. In addition, the capital structure for both Gaz Metro and Gazifere also includes preferred stock, which further reduces the long-term debt component of the capital structure for those two companies, providing these companies with an equity cushion Liberty does not have. Moreover, the deemed equity ratio for Liberty is lower than any of the authorized equity ratios for the operating companies held by the U.S. Gas proxy group. By comparison to other Canadian gas distributors, Liberty's equity ratio of 45.0 percent is reasonable,

80 Energir also has 7.5 percent preferred equity in its capital structure.
81 Gazifere also has 5.0 percent preferred equity in its capital structure.

considering its size and market risks. In comparison to the U.S. Gas proxy group, Liberty's current deemed equity ratio is low, especially given the small size of Liberty relative to the operating companies held by the Canadian and U.S. Gas proxy groups.

2. Analysis of Credit Metrics

Credit metrics provide a snapshot of how a 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, Morningstar DBRS and Fitch), or Ba1 and lower (for Moody's), being more volatile and higher risk. It is important to note that rating agencies analyze the default risk for *debt holders,* 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.[82]

Ordinarily, I would compare the credit metrics of the target company with the proxy group companies, where possible, to draw conclusions regarding financial risk. I am unable to do so in this case, however, because Liberty is not a rated entity due to its small size and dependence on its parent for both debt and equity. On a stand-alone basis, Liberty would be disadvantaged against its peers for raising debt in capital markets, and would pay a premium.

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[82] *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."

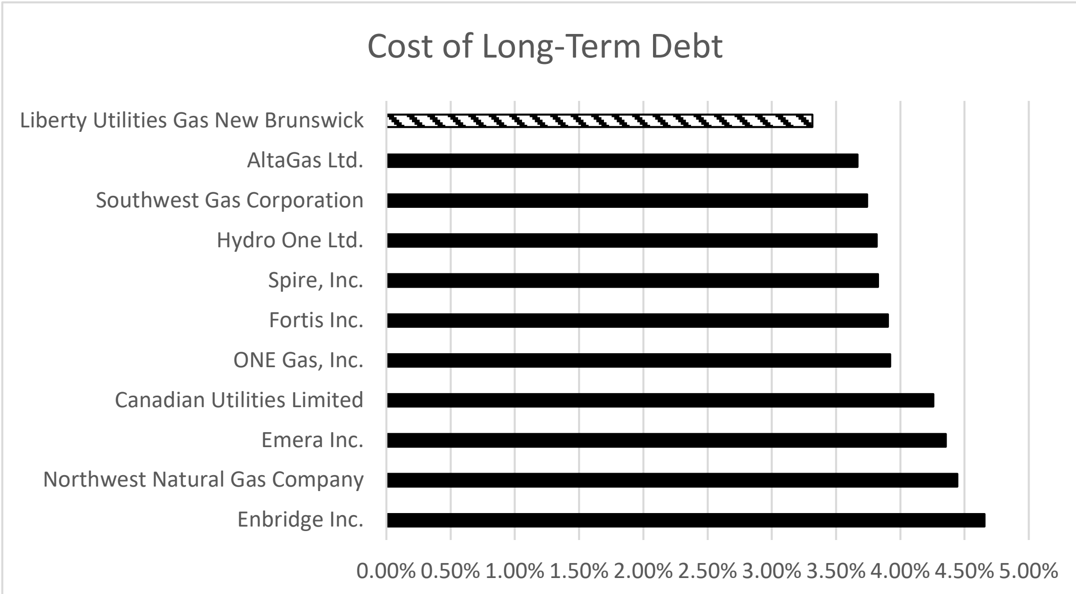
J. Deemed Equity Recommendation for Liberty

In the Board's 2010 decision, the deemed equity ratio for Liberty was reduced from 50.0 percent to 45.0 percent. This change was made even though Liberty was still considered to be in the development period. It was not until 2016 that the Board determined that Liberty would no longer be in the development period once the initial franchise agreement expired in 2019. My risk assessment evidence indicates that Liberty has higher risk than most other investor-owned gas distributors in Canada, as well as the Canadian and North American proxy group companies. In particular, Liberty is significantly smaller both in terms of customer count and implied market capitalization than its peer group; Liberty has greater volumetric risk and declining average use per customer; and Liberty's competitive risk and supply risk both have increased since 2010. For all of these reasons, I recommend that the deemed equity ratio for Liberty be maintained at a minimum of 45.0 percent, with 50.0 percent not an unreasonable target.

K. Cost of Debt for Liberty

Liberty's current cost of debt is based on a 30-year debt issuance by the parent company (Liberty Utilities (Canada) LP) of C$200 million in February 2020 with an interest rate of 3.315 percent. C$155 million of this amount was loaned by the parent to Liberty under a promissory note dated April 1, 2020. I compared Liberty's debt cost to the embedded long-term debt cost for the companies in my North American proxy group, which have an average A- credit rating from S&P. That analysis reveals that Liberty's debt cost of 3.315 percent is 74 basis points lower than the average embedded debt cost for the North American proxy group of 4.06 percent. As shown in Figure 33, Liberty's debt cost is lower than any of the companies in the North American proxy group.

Figure 33: Long-term Debt Cost Comparison



My conclusion is that Liberty's low long-term debt cost provides an important cost advantage to customers that partly offsets the Company's higher than average requested ROE.

VIII. CONCLUSIONS AND RECOMMENDATIONS

As shown in Figure 34, the average results from the alternative models and proxy groups cover a range from 9.9 percent to 11.5 percent. As discussed in my risk assessment, a higher ROE than the average is justified based on the relative risk of Liberty in relation to the proxy group companies. I therefore consider 11.5 percent, the upper end of the proxy results for the Canadian Proxy Group using a forward-looking CAPM, most appropriate for Liberty. This reflects a 160 basis point differential over the lower risk U.S. proxy group benchmark using a forward-looking CAPM, which I believe is appropriate for a company of Liberty's risk profile.

Figure 34: Summary of Mean Results[83]

	CANADIAN UTILITY PROXY GROUP	U.S. GAS PROXY GROUP	NORTH AMERICAN PROXY GROUP
CONSTANT GROWTH DCF	12.05%	9.58%	10.95%
MULTI-STAGE DCF	10.92%	8.97%	10.05%
FORWARD-LOOKING CAPM	11.61%	11.44%	11.54%
ALTERNATIVE CAPM	10.12%	9.97%	10.06
RISK PREMIUM		9.71%	
AVERAGEWITH FORWARD-LOOKING CAPM	**11.5%**	**9.9%**	**10.8%**
AVERAGE WITH ALTERNATIVE CAPM	**11.0%**	**9.6%**	**10.4%**

These recommendations are based on a cost of capital analysis utilizing the DCF, CAPM and Risk Premium models, and a combination of Canadian, U.S. and North American proxy group companies. I have also considered the Board's regulatory precedents, including the 2016 determination that Liberty is no longer in the development period, Liberty's business and financial risks, and issues around the Development O&M deferral account and the Regulatory deferral account. Based on the foregoing, I recommend an authorized return for Liberty of 11.5 percent. Given the risk profile of Liberty relative to other companies in the Canadian and U.S. comparator groups, an equity ratio of 50.0 percent is my recommendation. This ratio is still below the average of larger and lower risk U.S. gas distributors, but higher than other Canadian gas distributors justified by a smaller customer, throughput and revenue profile which imposes greater business risk. These recommendations meet both the requirements of the fair return standard and stand-alone principle, as well as provide sufficient support for the financial integrity and soundness of Liberty.

[83] Results include 50 basis points for flotation costs and financing flexibility, except for Risk Premium results for U.S. proxy group.

Actual vs. Allowed ROEs Enbridge Gas and Union Gas

ENBRIDGE GAS

Year	Actual ROE(%)	Allowed ROE (%)	Actual - Allowed	Actual ROE(%)	Allowed ROE (%)
1990	13.60%	13.25%	0.35%	13.60%	13.25%
1991	13.29%	13.13%	0.16%	13.29%	13.13%
1992	13.40%	13.13%	0.27%	13.40%	13.13%
1993	14.43%	12.30%	2.13%	14.43%	12.30%
1994	12.49%	11.60%	0.89%	12.49%	11.60%
1995	12.66%	11.65%	1.01%	12.66%	11.65%
1996	13.14%	11.88%	1.26%	13.14%	11.88%
1997	13.00%	11.50%	1.50%	13.00%	11.50%
1998	11.97%	10.30%	1.67%	11.97%	10.30%
1999	10.77%	9.51%	1.26%	10.77%	9.51%
2000	10.83%	9.73%	1.10%	10.83%	9.73%
2001	10.03%	9.54%	0.49%	10.03%	9.54%
2002	11.81%	9.66%	2.15%	11.81%	9.66%
2003	9.94%	9.69%	0.25%	9.94%	9.69%
2004	10.83%	9.69%	1.14%	10.83%	9.69%
2005	10.34%	9.57%	0.77%	10.34%	9.57%
2006	10.34%	8.74%	1.60%	10.34%	8.74%
2007	9.78%	8.39%	1.39%	9.78%	8.39%
2008	10.21%	9.66%	0.55%	10.21%	9.66%
2009	11.20%	9.31%	1.89%	11.20%	9.31%
2010	11.08%	9.37%	1.71%	11.08%	9.37%
2011	10.38%	8.94%	1.44%	10.38%	8.94%
2012	9.57%	8.52%	1.05%	9.57%	8.52%
2013	10.41%	8.93%	1.48%	10.41%	8.93%
2014	10.46%	9.36%	1.10%	10.46%	9.36%
2015	9.82%	9.30%	0.52%	9.82%	9.30%
2016	9.42%	9.19%	0.23%	9.42%	9.19%
2017	10.27%	8.78%	1.49%	10.27%	8.78%
2018	10.76%	9.00%	1.76%	10.76%	9.00%
2019	10.47%	8.98%	1.49%	10.47%	8.98%
2020	8.72%	8.52%	0.20%	8.72%	8.52%
2021	9.17%	8.34%	0.83%	9.17%	8.34%
2022	9.36%	8.66%	0.70%	9.36%	8.66%

ENBRIDGE GAS

(1990-2018)	**Actual-Allowed**	**(1990-2018)**	**Actual ROEs**	**Allowed ROEs**	**Actual-Allowed**
Average	**1.12%**	**Average**	**11.25%**	**10.12%**	**1.12%**
Median	1.14%	**Median**	10.77%	9.57%	1.14%
Max	2.15%	**Max**	14.43%	13.25%	2.15%
Min	0.16%	**Min**	9.42%	8.39%	0.16%
StdDev	0.59%	**StdDev**	1.41%	1.47%	0.59%
CV(ROE)		**CV(ROE)**	**0.1253**	0.1456	
(1990-2022)		**(1990-2022)**			
Average	**1.09%**	**Average**	**11.03%**	**9.94%**	**1.09%**
Median	1.10%	**Median**	10.47%	9.51%	1.10%
Max	2.15%	**Max**	14.43%	13.25%	2.15%
Min	0.16%	**Min**	8.72%	8.34%	0.16%
StdDev	0.58%	**StdDev**	1.47%	1.47%	0.58%
CV(ROE)		**CV(ROE)**	**0.1331**	0.1476	

Actual-Allowed	**(2013-2022)**	**Actual ROEs**	**Allowed ROEs**	**Actual-Allowed**
0.98%	**Average**	**9.89%**	**8.91%**	**0.98%**
0.97%	**Median**	10.05%	8.96%	0.97%
1.76%	**Max**	10.76%	9.36%	1.76%
0.20%	**Min**	8.72%	8.34%	0.20%
0.57%	**StdDev**	0.69%	0.33%	0.57%
	CV(ROE)	**0.0693**	0.0375	

UNION GAS (1990-2018)

Year	Actual ROE (%)	Allowed ROE (%)	Actual - Allowed	Actual ROE(%)	Allowed ROE (%)
1990	13.30%	13.75%	-0.45%	13.30%	13.75%
1991	10.70%	13.50%	-2.80%	10.70%	13.50%
1992	11.50%	13.50%	-2.00%	11.50%	13.50%
1993	14.00%	13.00%	1.00%	14.00%	13.00%
1994	15.30%	12.50%	2.80%	15.30%	12.50%
1995	12.17%	11.75%	0.42%	12.17%	11.75%
1996	13.47%	11.75%	1.72%	13.47%	11.75%
1997	12.19%	11.00%	1.19%	12.19%	11.00%
1998	8.03%	10.44%	-2.41%	8.03%	10.44%
1999	8.76%	9.61%	-0.85%	8.76%	9.61%
2000	10.62%	9.95%	0.67%	10.62%	9.95%
2001	9.30%	9.95%	-0.65%	9.30%	9.95%
2002	10.75%	9.95%	0.80%	10.75%	9.95%
2003	12.75%	9.95%	2.80%	12.75%	9.95%
2004	11.37%	9.62%	1.75%	11.37%	9.62%
2005	11.50%	9.62%	1.88%	11.50%	9.62%
2006	9.24%	9.62%	-0.38%	9.24%	9.62%
2007	9.99%	8.54%	1.45%	9.99%	8.54%
2008	13.35%	8.54%	4.81%	13.35%	8.54%
2009	11.22%	8.54%	2.68%	11.22%	8.54%
2010	10.91%	8.54%	2.37%	10.91%	8.54%
2011	10.38%	8.54%	1.84%	10.38%	8.54%
2012	11.07%	8.54%	2.53%	11.07%	8.54%
2013	10.67%	8.93%	1.74%	10.67%	8.93%
2014	10.72%	8.93%	1.79%	10.72%	8.93%
2015	9.89%	8.93%	0.96%	9.89%	8.93%
2016	9.24%	8.93%	0.31%	9.24%	8.93%
2017	9.15%	8.93%	0.22%	9.15%	8.93%
2018	9.64%	8.93%	0.71%	9.64%	8.93%

UNION GAS

(1990-2018)	**Actual-Allowed**	**(1990-201**	**Actual RO**	**Allowed R**	**Actual-Allowed**
Average	**0.93%**	**Average**	**11.08%**	**10.15%**	**0.93%**
Median	1.00%	**Median**	10.75%	9.62%	1.00%
Max	4.81%	**Max**	15.30%	13.75%	4.81%
Min	-2.80%	**Min**	8.03%	8.54%	-2.80%
StdDev	1.68%	**StdDev**	1.71%	1.70%	1.68%
CV(ROE)		**CV(ROE)**	**0.1546**	0.1674	

Actual-Allowed	**2013-2018**	**ctual ROE**	**llowed RO**	**tual-Allowed**
0.96%	**Average**	**9.89%**	**8.93%**	**0.96%**
0.84%	**Median**	9.77%	8.93%	0.84%
1.79%	**Max**	10.72%	8.93%	1.79%
0.22%	**Min**	9.15%	8.93%	0.22%
0.68%	**StdDev**	0.68%	0.00%	0.68%
	CV(ROE)	**0.0691**	0.0000	

ROEs for US and Canadian Holdcos

US Utility ROES	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ATMOS ENERGY CORP	9.85%	10.23%	10.01%	10.52%	11.13%	13.90%	9.71%	9.58%	9.05%	8.94%
NEW JERSEY RESOURCES CORP	13.50%	15.32%	17.46%	11.58%	10.99%	17.58%	11.41%	11.42%	6.78%	15.95%
NiSource Inc.	9.30%	8.79%	5.72%	8.38%	3.06%	-1.43%	6.57%	-1.46%	10.31%	13.11%
Northwest Natural Holding Company	8.15%	7.73%	6.94%	7.22%	-6.98%	8.58%	7.58%	8.75%	8.63%	8.18%
ONE Gas Inc	8.29%	7.24%	6.55%	7.51%	8.47%	8.61%	8.95%	9.00%	9.01%	8.99%
South Jersey Industries Inc.	10.44%	11.03%	10.67%	10.21%	-0.32%	1.61%	5.72%	10.18%	4.83%	
Southwest Gas Corporation	10.67%	9.72%	8.97%	9.33%	11%	8.96%	8.99%	8.97%	7.13%	-6.76%
Spire Inc	6.40%	6.62%	8.88%	8.63%	8.60%	10.09%	7.85%	3.22%	10.82%	8.24%
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Average	9.58%	9.59%	9.40%	9.17%	5.76%	8.49%	8.35%	7.46%	8.32%	8.09%
Median	9.58%	9.26%	8.93%	8.98%	8.54%	8.79%	8.40%	8.99%	8.82%	8.94%
Max	13.50%	15.32%	17.46%	11.58%	11.15%	17.58%	11.41%	11.42%	10.82%	15.95%
Min	6.40%	6.62%	5.72%	7.22%	-6.98%	-1.43%	5.72%	-1.46%	4.83%	-6.76%
StDev	2.11%	2.77%	3.69%	1.52%	6.62%	6.10%	1.81%	4.33%	1.97%	7.18%

Canadian Holding Companies	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Algonquin Power	1.76%	5.96%	6.53%	7.14%	7.62%	6.40%	15.63%	17.77%	4.79%	
AltaGas Inc.	9.63%	3.86%	0.33%	4.59%	0.88%	-11.15%	13.21%	8.17%	3.89%	6.26%
Canadian Utilities Ltd.	13.68%	15.07%	6.43%	11.69%	8.73%	11.71%	17.43%	6.93%	6.43%	10.74%
Emera Inc.	11.59%	17.00%	12.85%	4.79%	4.30%	10.36%	8.91%	11.90%	6.04%	10.11%
Fortis Inc.	8.06%	5.45%	9.75%	5.56%	7.31%	7.78%	10.40%	7.12%	7.09%	7.18%
Hydro One Ltd.	11.81%	9.67%	8.12%	7.58%	6.80%	-0.94%	8.40%	17.78%	9.01%	9.46%
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Average	9.42%	9.50%	7.34%	6.89%	5.94%	4.03%	12.33%	11.61%	6.21%	8.75%
Median	10.61%	7.82%	7.33%	6.35%	7.06%	7.09%	11.81%	10.04%	6.24%	9.46%
Max	13.68%	17.00%	12.85%	11.69%	8.73%	11.71%	17.43%	17.78%	9.01%	10.74%
Min	1.76%	3.86%	0.33%	4.59%	0.88%	-11.15%	8.40%	6.93%	3.89%	6.26%
StDev	4.22%	5.44%	4.18%	2.65%	2.88%	8.65%	3.70%	5.10%	1.79%	1.94%

2013-2022

		Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
1	ATMOS ENERGY CORP	10.29%	9.93%	13.90%	8.94%	1.42%	0.138
2	NEW JERSEY RESOURCES CORP	13.20%	12.54%	17.58%	6.78%	3.41%	0.258
3	NiSource Inc.	6.24%	7.48%	13.11%	-1.46%	4.86%	0.780
4	Northwest Natural Holding Compan	6.48%	7.94%	8.75%	-6.98%	4.77%	0.736
5	ONE Gas Inc	8.26%	8.54%	9.01%	6.55%	0.87%	0.105
6	South Jersey Industries Inc.	7.15%	10.18%	11.03%	-0.32%	4.34%	0.607
7	Southwest Gas Corporation	7.71%	8.98%	11.15%	-6.76%	5.20%	0.674
8	Spire Inc	7.94%	8.42%	10.82%	3.22%	2.14%	0.270
		Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
	Average	**8.41%**	**9.25%**	11.92%	1.25%	3.38%	**0.446**
	Median	7.82%	8.76%	11.09%	1.45%	3.87%	0.438
	Max	13.20%	12.54%	17.58%	8.94%	5.20%	0.780
	Min	6.24%	7.48%	8.75%	-6.98%	0.87%	0.105
	StDev	2.31%	1.62%	2.89%	6.13%	1.69%	0.280

	2013-2022	**Average**	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
1	Algonquin Power	8.18%	6.53%	17.77%	1.76%	5.15%	0.630
2	AltaGas Inc.	3.97%	4.24%	13.21%	-11.15%	6.60%	1.664
3	Canadian Utilities Ltd.	10.88%	11.22%	17.43%	6.43%	3.79%	0.349
4	Emera Inc.	9.79%	10.24%	17.00%	4.30%	3.94%	0.402
5	Fortis Inc.	7.57%	7.25%	10.40%	5.45%	1.57%	0.208
6	Hydro One Ltd.	8.77%	8.71%	17.78%	-0.94%	4.62%	0.527

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**8.19%**	**8.03%**	15.60%	0.98%	4.28%	**0.630**
Median	8.47%	7.98%	17.22%	3.03%	4.28%	0.464
Max	10.88%	11.22%	17.78%	6.43%	6.60%	1.664
Min	3.97%	4.24%	10.40%	-11.15%	1.57%	0.208
StDev	2.38%	2.56%	3.08%	6.51%	1.67%	0.527

Apex Utilities Inc.
Alberta Utilities Commission Rule 005 Filing
May 13, 2022

Apex Utilities Inc.
5509 45th Street
Leduc, AB T9E 6T6

May 13, 2022

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, AB T2P 0G5

Re: Apex Utilities Inc. – 2021 Rule 005 Filing

In accordance with the Alberta Utilities Commission (AUC) Rule 005: Annual Reporting Requirements of Financial and Operational Results, Apex Utilities Inc. (AUI) submits its 2021 Rule 005 Filing package including its 2021 audited financial statements.

If you have any questions, please contact the writer.

Yours truly,

[*Electronically signed*]

Chad Drvaric
Manager, Regulatory

APEX UTILITIES INC

2021 ANNUAL REPORT OF NATURAL GAS DISTRIBUTION SERVICE OPERATIONAL AND FINANCIAL RESULTS

Apex Utilities Inc.
5509 45 Street
Leduc, AB T9E 6T6

May 13, 2022

Apex Utilities Inc.
SUMMARY OF REVENUE REQUIREMENT
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Normalized	2021 Actual[1]	2021 Normalized[1,2]	2021 Normalized vs. 2020 Normalized $	2021 Normalized vs. 2020 Normalized %
1	Return on Rate Base	Sch. 2	$ 23,960	$ 26,686	$ 26,752	$ 2,793	11.7%
2	Operating and Maintenance Expense[3]	Sch. 3	42,099	42,497	42,497	398	0.9%
3	Depreciation & Amortization Expense	Sch. 4	20,121	21,903	21,903	1,782	8.9%
4	Deferral Account Amortization[3]	Sch. 3, Sch. 9	1,004	789	789	(215)	-21.4%
5	Income Tax Expense	Sch. 5, Sch. 10	1,251	(79)	(59)	(1,310)	-104.7%
6	Sub Total Utility Revenue Requirement		88,435	91,797	91,883	3,448	3.9%
7	Flow Through Expenses[4]	Sch. 10	32,880	47,414	47,808	14,928	45.4%
8	Total Utility Revenue Requirement		$ 121,315	$ 139,211	$ 139,691	$ 18,376	15.1%
	Detailed Revenue						
9	Delivery Rate Revenue	Sch. 6	$ 84,157	$ 89,335	$ 89,421	$ 5,264	6.3%
10	Flow Through Revenues[4]	Sch. 6	32,880	$ 47,414	$ 47,808	14,928	45.4%
11	Penalty Revenue	Sch. 6	129	$ 179	$ 179	50	39.1%
12	Revenue Deficiency (Excess)	Sch. 6	2,968	$ (129)	$ (129)	(3,098)	-104.4%
13	Deficiency Adjustment - Prior Year	Sch. 6	24	$ 932	$ 932	908	3850.2%
14	Property Tax Revenue		-	$ -	$ -	-	0.0%
15	Other Revenue	Sch. 1.1	1,157	$ 1,481	$ 1,481	324	28.0%
16	Utility Revenue	Sch. 6	$ 121,315	$ 139,211	$ 139,691	$ 18,376	15.1%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.
2 Normalized Revenue is Utility Revenue with an adjustment for weather variances to normal.
3 Operating and Maintenance Expense is net of Deferral Account Amortization on Line 4.
4 Flow through expenses and revenues include the Gas Costs and the Third Party Transportation Costs.

Guidelines:
(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Total Revenue Requirement must be reconciled on Schedule 10 to the Audited Financial Statements.
(3) Provide a detailed breakdown of items included in Revenue Offsets and Other Revenue in a supporting sub-schedule.
(4) Please identify flow through items and any reporting anomalies.
(5) List the flow through items included in line 8. Flow through items may or may not include franchise fees and natural gas supply.

Apex Utilities Inc.
OTHER UTILITY REVENUE DETAIL
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Normalized	2021 Actual[1]	2021 Normalized[1]	2021 Normalized vs. 2020 Normalized $	2021 Normalized vs. 2020 Normalized %
1	Other Utility Revenue	Sch. 1	$ 1,157	$ 1,481	$ 1,481	324	28.0%
2	Closed Rate Transportation	Sch. 6	132	143	143	11	8.7%
3	Service Work		231	12	12	(220)	-94.9%
4	AER Deposit Interest		4	3	3	(2)	-38.6%
5	Other Revenue		789	1,323	1,323	534	67.6%
6	Other Utility Revenue Total		$ 1,157	$ 1,481	$ 1,481	$ 324	28.0%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

SCHEDULE 2

Apex Utilities Inc.
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

2021

Line No.	Description	Cross Ref.	Mid-Year Capital	Deemed Ratio	Prorated Rate Base	Actual Cost Rate %	Return $	2021 Actual vs. 2020 Actual $	2021 Actual vs. 2020 Actual %
1	Debt		258,508	61.00%	258,508	4.229%	10,932	564	5.4%
2	Preferred Shares								
3	Common Equity		165,276	39.00%	165,276	9.532%	15,755	1,491	10.5%
4	Mid-Year Invested Capital	Sch. 2.1	$ 423,784	100.00%	423,784		26,686	2,054	8.3%
5	Return on Rate Base	Sch. 1					$ 26,686	$ 2,054	8.3%
6	No Cost Capital		61,160						
7	Total Mid-Year Rate Base	Sch. 2.1	$ 484,944						

2021 Actual Weather Normalized

Line No.	Description	Cross Ref.	Mid-Year Capital	Deemed Ratio	Prorated Rate Base	Actual Cost Rate %	Return $	2021 Normal vs. 2020 Normal $	2021 Normal vs. 2020 Normal %
8	Debt		258,508	61.00%	258,508	4.229%	10,932	564	5.4%
9	Preferred Shares								
10	Common Equity		165,276	39.00%	165,276	9.572%	15,820	2,229	16.4%
11	Mid-Year Invested Capital	Sch. 2.1	$ 423,784	100.00%	423,784		26,752	2,793	11.7%
12	Return on Rate Base	Sch. 1					$ 26,752	$ 2,793	11.7%
13	No Cost Capital		61,160						
14	Total Mid-Year Rate Base	Sch. 2.1	$ 484,944						

2020

Line No.	Description	Cross Ref.	Mid-Year Capital	Deemed Ratio	Prorated Rate Base	Actual Cost Rate %	Return $
15	Debt		241,294	61.00%	241,294	4.297%	10,368
16	Preferred Shares						
17	Common Equity		154,270	39.00%	154,270	9.246%	14,264
18	Mid-Year Invested Capital	Sch. 2.1	$ 395,563	100.00%	395,563		24,632
19	Return on Rate Base						$ 24,632
20	No Cost Capital		62,173				
21	Total Mid-Year Rate Base	Sch. 2.1	$ 457,737				

2020 Actual Weather Normalized

Line No.	Description	Cross Ref.	Mid-Year Capital	Deemed Ratio	Prorated Rate Base	Actual Cost Rate %	Return $
22	Debt		241,294	61.00%	241,294	4.297%	10,368
23	Preferred Shares						
24	Common Equity		154,270	39.00%	154,270	8.810%	13,591
25	Mid-Year Invested Capital	Sch. 2.1	$ 395,563	100.00%	395,563		23,960
26	Return on Rate Base	Sch. 1					$ 23,960
27	No Cost Capital		62,173				
28	Total Mid-Year Rate Base	Sch. 2.1	$ 457,737				

Guidelines:
(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Provide the breakdown of the items making up the difference (including disallowed items etc.).
(3) Common equity is based on the approved equity ratio.
(4) Please complete these schedules using the approved deemed capital structure.
(5) The cost rate for the common equity should be inferred from the return and prorated rate base of common equity.

Apex Utilities Inc.
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Normal[1]	2021 Normal[1]	2021 Normalized vs. 2020 Normalized $	%
	Gross Property, Plant and Equipment					
1	Opening Balance		$ 643,559	$ 678,583	$ 35,024	5.4%
2	Additions	Sch. 4.2	41,895	55,317	13,421	32.0%
3	Retirements		(6,871)	(9,244)	(2,373)	34.5%
4	Adjustments		-	(16)	(16)	0.0%
5	Salvage Additions		-	-	-	0.0%
6	Closing Balance	Sch. 4.1	678,583	724,640	$ 46,057	6.8%
7	**Gross PPE, Mid-Year**		$ 661,071	$ 701,612	$ 40,541	6.1%
8	CWIP, Mid-Year		12,905	11,892	(1,013)	-7.8%
9	Gross PPE less CWIP, Mid-Year		$ 648,167	$ 689,720	$ 41,553	6.4%
10	Disallowed Plant, Mid-Year		-	-	-	0.0%
11	Gross PPE less CWIP, Mid-Year		$ 648,167	$ 689,720	$ 41,553	6.4%
	Accumulated Depreciation					
12	Opening Balance		$ 200,799	$ 215,544	14,745	7.3%
13	Depreciation Expense		22,333	24,171	1,838	8.2%
14	Retirements		(6,871)	(9,244)	(2,373)	34.5%
15	Salvage		153	176	24	15.5%
16	Transfers/Adjustment		181	180	(1)	-0.8%
17	Cost of Removal		(1,051)	(1,159)	(107)	10.2%
18	Closing Balance	Sch. 4.1	215,544	229,669	14,125	6.6%
19	**Accumulated Depreciation, Mid-Year**		$ 208,171	$ 222,606	$ 14,435	6.9%
20	**Plant in Service, Mid-Year**		$ 452,900	$ 479,006	$ 26,106	5.8%
	Working Capital, Mid-Year					
21	Cash		$ 4,223	$ 5,301	$ 1,079	25.5%
22	Materials and Supplies		225	272	47	21.1%
23	Prepayments and Deferrals		389	365	(25)	-6.4%
24	Financial Items		-	-	-	0.0%
25	Other (Regulatory costs)		-	-	-	0.0%
26	**Total Working Capital, Mid-Year**		$ 4,837	$ 5,938	$ 1,101	22.8%
27	**Rate Base, Mid-Year**	Sch. 2	$ 457,737	$ 484,944	$ 27,207	5.9%
	Contributions in Aid of Construction					
28	Opening Balance		$ 111,055	$ 111,664	$ 609	0.5%
29	Closing Balance		111,664	112,522	857	0.8%
30	**Contributions in Aid of Construction, Mid-Year**		$ 111,360	$ 112,093	$ 733	0.7%
	Amortization of Contributions					
31	Opening Balance		$ 48,396	$ 49,977	$ 1,581	3.3%
32	Closing Balance		49,977	51,889	1,912	3.8%
33	**Amortization of Contributions, Mid-Year**		$ 49,187	$ 50,933	$ 1,746	3.6%
34	**Rate Base net of CIAC, Mid-Year**	Sch. 2	$ 395,563	$ 423,784	$ 28,220	7.1%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:
(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

Apex Utilities Inc.
SUMMARY OF MID YEAR CAPITAL STRUCTURE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000's)

Line No.	Description	Cross Reference	Current Year End	Previous Year End	2021 Actual Mid Year Capital	2021 Actual Mid Year Ratio	2021 Actual Year End Ratio
1	Long Term Debt	Sch 2.3	263,000	238,000	250,500	60.95%	60.80%
2	Preferred Shares	Sch 2.4	-	-	-		
3	Common Equity	Sch 11	169,536	151,409	160,473	39.05%	39.20%
4	**Total Mid Year Invested Capital**		432,536	389,409	410,973	100%	100%

Note:

(1) Capital Structure pertains to regulated business

(2) Year end balances to be reconciled to Audited Financial Statements on Schedule 11

SCHEDULE 2.3

Apex Utilities Inc.
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

2021 Actual & Normal

Line No.	Cross Ref.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate	2021 Actual vs. 2020 Actual $	2021 Actual vs. 2020 Actual %
1		2014 Debt	n/a	2014	2024	n/a	40,000	-	40,000	4.48%	40,000	1,792	4.480%		
2		2014 Debt	n/a	2014	2044	n/a	20,000	-	20,000	5.21%	20,000	1,042	5.210%		
3		2015 Debt	n/a	2015	2025	n/a	15,000	-	15,000	3.91%	15,000	587	3.910%		
4		2016 Debt	n/a	2016	2026	n/a	45,000	-	45,000	4.20%	45,000	1,890	4.200%		
5		2017 Debt	n/a	2017	2026	n/a	10,000	-	10,000	3.76%	10,000	376	3.760%		
6		2017 Debt	n/a	2017	2044	n/a	20,000	-	20,000	4.88%	20,000	976	4.880%		
7		2017 Debt	n/a	2017	2047	n/a	30,000	-	30,000	5.03%	30,000	1,509	5.030%		
8		2018 Debt	n/a	2018	2028	n/a	15,000	-	15,000	4.34%	15,000	651	4.340%		
9		2019 Debt	n/a	2019	2028	n/a	23,000	-	23,000	3.12%	23,000	718	3.120%		
10		2020 Debt	n/a	2020	2027	n/a	30,000	-	30,000	3.25%	30,000	975	3.250%		
11		2021 Debt	n/a	2021	2051	n/a	15,000	-	15,000	3.86%	15,000	579	3.860%		
12		Current Year-End Balance					$ 263,000	$ -	$ 263,000		$ 263,000	$ 11,094	4.218%		
13	Sch. 2	Prior Year-End Balance									248,000	10,515	4.240%		
14	Sch. 2	**Mid-Year Balance**									$ 255,500	$ 10,805	4.229%	$ 363	3.48%

2020 Actual & Normal

Line No.	Cross Ref.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
15		2012 Debt	n/a	2012	2020	n/a	$ 20,000	$ -	$ 20,000	4.14%	$ -	$ -	0.000%
16		2014 Debt	n/a	2014	2024	n/a	40,000	-	40,000	4.48%	40,000	1,792	4.480%
17		2014 Debt	n/a	2014	2044	n/a	20,000	-	20,000	5.21%	20,000	1,042	5.210%
18		2015 Debt	n/a	2015	2025	n/a	15,000	-	15,000	3.91%	15,000	587	3.910%
19		2016 Debt	n/a	2016	2026	n/a	45,000	-	45,000	4.20%	45,000	1,890	4.200%
20		2017 Debt	n/a	2017	2026	n/a	10,000	-	10,000	3.76%	10,000	376	3.760%
21		2017 Debt	n/a	2017	2044	n/a	20,000	-	20,000	4.88%	20,000	976	4.880%
22		2017 Debt	n/a	2017	2047	n/a	30,000	-	30,000	5.03%	30,000	1,509	5.030%
23		2018 Debt	n/a	2018	2028	n/a	15,000	-	15,000	4.34%	15,000	651	4.340%
24		2019 Debt	n/a	2019	2028	n/a	23,000	-	23,000	3.12%	23,000	718	3.120%
25		2020 Debt	n/a	2020	2027	n/a	30,000	-	30,000	3.25%	30,000	975	3.250%
26		2020 Year-End Balance					$ 268,000	$ -	$ 268,000		$ 248,000	$ 10,515	4.240%
27	Sch. 2	2019 Year-End Balance									238,000	10,368	4.356%
28	Sch. 2	**Mid-Year Balance**									$ 243,000	$ 10,442	4.297%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Include any short-term interest-bearing debt.

(2) Total debt should equal the financial statement debt and is not expected to equal the deemed debt indicated on Schedule 2.

(3) Please provide details affecting regulated financial results such as placeholders and R & V issues underway.

Apex Utilities Inc.
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

2021 Actual [1]

Line No.	Cross Ref.	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1				0.00%	0	0	0	0	
2				0.00%	0	0	0	0	
3				0.00%	0	0	0	0	
4				0.00%	0	0	0	0	
5		Current Year-End Balance			0	0	0	0	0.00%
6		Prior Year-End Balance					0	0	0.00%
7		**Mid-Year Balance**					0	0	0.00%

[1] AUI does not have any preferred share capital.

SCHEDULE 2.5

Apex Utilities Inc.

RECONCILIATION

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.					2021 Actual
1	Return on mid-year rate base financed by common equity			$	15,755
2	Return on book value of common equity as per financial statements				15,979
3	Difference			$	(224)
	Reconciliation				
4	**Return on Rate Base Financed by Common Equity**			**$**	**15,755**
	Adjustments				
	Revenue Adjustments				
5	Non-Regulatory Revenue	846			
6	Reclass Property Taxes	2,277			
7	2020 Y and K Factors True-Up from Provision to Filling	(32)			
8	Reclass Negative Salvage Depreciation	(4,213)			
9	Reclass Cost of Removal	1,159			
10	Deferred Revenue	-			
11	Other	-			
12	Subtotal		37		
	Expense Adjustments				
13	**OM&A**	-			
	Disallowed and Not Applied for Expenses				
14	Inter-Affiliate Costs	(616)			
15	Community Sponsorship	(42)			
16	STIP	(93)			
	Other Expense Adjustments				
17	Reclass Property Taxes	(2,277)			
18	Reclass Negative Salvage Depreciation	4,213			
19	Reclass Cost of Removal	(1,159)			
20	Financing	338			
21	Foreign Exchange	(59)			
22	Other	-			
23	Subtotal		305		
24	Sub-Total Revenue and Expense Adjustments				342
25	Tax Effect @ 23%				(79)
26	Excluded Tax Additions	-			
27	Excluded Tax Deductions	-			
28	Subtotal		-		
29	Tax Effect @ 23%				-
30	Deferred Income Taxes				(172)
31	Other Tax Adjustments				133
32	Loss (Carryback)/Forward	-			
33	Tax Effect				-
34	**Return on book value of common equity as per financial statements**			**$**	**15,979**

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Please identify key areas creating the difference between the financial return and the regulated utility return contained in these spreadsheets.

(2) As a rule of thumb, five to six main points causing the variance is recommended but the utilities explanation is not limited to that number.

SCHEDULE 2.6

Apex Utilities Inc.
SUMMARY OF DEGREE DAYS & TRANSPORTATION UNITS BY CLASSIFICATION
FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	2020 Normalized[1]	2021 Actual[1]	2021 Normalized[1]	2021 Normalized vs. 2020 Normalized #	%
1	Degree Days	See attached schedules 2.6.1				
	Number of Year End Customers					
2	Residential	59,744	60,219	60,219	475	0.8%
3	Commercial	7,478	7,446	7,446	(32)	-0.4%
4	Rural	14,047	14,044	14,044	(3)	0.0%
5	Irrigation	139	131	131	(8)	-5.8%
6	Large General Service	142	141	141	(1)	-0.7%
7	Demand	61	59	59	(2)	-3.3%
8	Producer	2	2	2	-	0.0%
9	Other Distribution	1	1	1	-	0.0%
10	Total Customers	81,614	82,043	82,043	429	0.5%
	Sales & Transportation - TJ					
11	Residential	6,869	6,900	6,906	37	0.5%
12	Commercial	5,056	5,121	5,133	76	1.5%
13	Rural	2,858	2,828	2,838	(21)	-0.7%
14	Irrigation	42	44	44	2	5.5%
15	Large General Service	1,274	1,256	1,268	(6)	-0.5%
16	Demand	2,356	2,423	2,423	67	2.8%
17	Producer	352	821	821	470	133.4%
18	Other Distribution	46	34	34	(12)	-25.6%
19	Total Throughput	18,854	19,429	19,468	614	3.3%
	Producer					

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

2 Prior year sales and transportation volumes were updated for residential, commercial, rural, large general service and demand due to a report error corrected in 2021.

Guidelines:

(1) Provide the degree day methodology used to determine degree day information.

(2) Please leave this schedule blank if the utility financial results are not effected by weather.

Apex Utilities Inc.
SUMMARY OF DEGREE DAYS AT 15 DEGREES CELSIUS
FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	District	Actual 2021	Normal Degree Days 2021	Normal Degree Days 2020	Variance Col.[b]-[c]	
		[a]	[b]	[c]	[d] Qty	[e] %
1	Athabasca	4,731.7	4,773.2	4,807.0	(33.8)	-0.7%
2	Barrhead / Westlock	4,599.0	4,479.0	4,496.6	(17.6)	-0.4%
3	Bonnyville	4,824.3	4,806.1	4,831.0	(24.9)	-0.5%
4	Drumheller	4,757.5	4,804.2	4,836.2	(32.0)	-0.7%
5	Grande Cache	4,768.6	4,646.0	4,669.6	(23.5)	-0.5%
6	Hanna	4,757.5	4,804.2	4,836.2	(32.0)	-0.7%
7	High Level	5,967.1	5,790.3	5,816.8	(26.5)	-0.5%
8	Leduc	4,682.8	4,744.2	4,769.1	(24.8)	-0.5%
9	Morinville	4,599.0	4,479.0	4,496.6	(17.6)	-0.4%
10	Pincher Creek	3,372.7	3,519.8	3,565.2	(45.4)	-1.3%
11	St. Paul	4,779.7	4,854.7	4,879.6	(25.0)	-0.5%
12	Southeast	3,535.1	3,674.5	3,703.3	(28.8)	-0.8%
13	Stettler	4,617.2	4,623.0	4,643.6	(20.5)	-0.4%
14	Three Hills	4,617.2	4,623.0	4,643.6	(20.5)	-0.4%
15	Two Hills	4,779.7	4,854.7	4,879.6	(25.0)	-0.5%

SCHEDULE 3

Apex Utilities Inc.
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Normalized[1]	2021 Actual[1]	2021 Normalized[1]	2021 Normalized vs. 2020 Normalized $	%
	Operating & Maintenance Expense						
1	Transmission (Operating)		$ 788	$ 864	$ 864	$ 76	9.7%
2	Distribution (Operating)		12,519	11,542	11,542	(978)	-7.8%
3	General (Operating)		2,056	2,085	2,085	28	1.4%
4	Advertising & Promotion		63	56	56	(7)	-10.8%
5	Customer Accounting		3,769	4,540	4,540	771	20.5%
6	Administration and General		21,847	22,102	22,102	255	1.2%
7	Property Tax Expense		136	139	139	2	1.6%
8	Transmission (Maintenance)		907	981	981	74	8.2%
9	Distribution (Maintenance)		1,362	1,113	1,113	(249)	-18.3%
10	General (Maintenance)		643	614	614	(30)	-4.6%
11	**Total Operating & Maintenance Expense**		$ 44,093	$ 44,037	$ 44,037	$ (56)	-0.1%
	Disallowed / Not Applied-For Items						
12	Inter-Affiliate Costs		$ (900)	$ (616)	$ (616)	$ 284	-31.5%
13	Community Sponsorship		(21)	(42)	(42)	(21)	99.1%
14	STIP		(68)	(93)	(93)	(25)	36.4%
15	**Total Disallowed / Not Applied-For Items**		$ (989)	$ (750)	$ (750)	$ 238	-24.1%
16	**Operating & Maintenance Expense - Net**	Sch. 10	$ 43,104	$ 43,286	$ 43,286	$ 182	0.4%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Global reductions refers to the reduction of fees chargeable as deemed in the rate application decision.

(3) Please add line items as needed to more clearly identify major O&M expenses.

SCHEDULE 4

Apex Utilities Inc.
SUMMARY OF DEPRECIATION
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2021 Actual[1]	2021 Normalized[1]	2020 Normalized[1]	2021 Normalized vs. 2020 Normalized $	%
	Depreciation Expense						
1	Straight Line Equal Life Group		$ 24,171	$ 24,171	$ 22,333	$ 1,838	8.2%
2	Finance Lease		31	31	33	(3)	0.0%
3	Sub-total		24,202	24,202	22,366	1,838	8.2%
	Amortization of Contributions						
4	Straight Line Equal Life Group		(1,949)	(1,949)	(1,918)	(31)	1.6%
5	Sub-total		(1,949)	(1,949)	(1,918)	(31)	1.6%
6	Capitalized Depreciation		(349)	(349)	(327)	(22)	6.6%
7	Sub-total		(349)	(349)	(327)	(22)	6.6%
8	**Net Depreciation Expense - Utility**	Sch. 1	$ 21,903	$ 21,903	$ 20,121	$ 1,785	8.9%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

SCHEDULE 4.1

Apex Utilities Inc.
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

CAPITAL ASSETS

Line No.	Property Group	Cross Ref.	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
1	Intangible Plant		$ 272	$ -	$ -	$ -	$ -	$ 272
2	Transmission Plant		123,778	5,270	(118)	0	-	128,930
3	Distribution Plant		481,866	25,979	(1,536)	(17)	0	506,292
4	General Plant		72,669	24,067	(7,590)	-	-	89,146
5	**Subtotal**	Sch. 4.2	678,585	55,317	(9,244)	(17)	0	724,640
6	Construction Work in Progress (CWIP)		16,106	(8,428)	-	-	-	7,678
7	**Total Utility**	Sch. 2.1	$ 694,691	$ 46,889	$ (9,244)	$ (17)	$ 0	$ 732,318

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross Ref.	Balance at 12/31/2020	Depreciation Provision	2021 Retirements	2021 COR/Salvage	2021 Adjustments	Balance at 12/31/2021
8	Intangible Plant		$ 272	$ -	$ -	$ -	$ -	$ 272
9	Natural Gas Production Plant		-	-	-	-	-	-
10	Transmission Plant		34,208	2,400	(118)	-	181	36,671
11	Distribution Plant		123,637	10,533	(1,536)	-	(1)	132,633
12	General Plant		32,582	7,026	(7,590)	176	-	32,194
13	**Subtotal**		190,699	19,958	(9,244)	176	181	201,771
14	Negative Salvage / Cost of Removal		24,844	4,213	-	(1,159)	-	27,898
15	**Total Utility**	Sch. 2.1	$ 215,543	$ 24,171	$ (9,244)	$ (982)	$ 181	$ 229,669

Guidelines:
(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Provide a detailed breakdown of items included in "Other", in a supporting sub-schedule.
(3) Year-end balances for each category must be reconciled on Schedule 11 to the audited Balance Sheet.

Apex Utilities Inc.
SUMMARY OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Additions	2021 Additions	2021 vs. 2020 $	2021 vs. 2020 %
	TRANSMISSION PLANT					
1	Compressor Structures		$ 3	$ -	$ (3)	-100.0%
2	Measuring & Regulating Structures		494	455	(39)	-8.0%
3	Mains		1,294	1,821	528	40.8%
4	Compressor Equipment		-	-	-	0.0%
5	Measuring & Regulating Equipment		3,404	2,994	(410)	-12.0%
6	**Total Transmission Plant**		$ 5,194	$ 5,270	$ 76	1.5%
	DISTRIBUTION PLANT					
7	Land Rights		$ 55	$ -	$ (55)	-100.0%
8	Services		13,639	12,458	(1,181)	-8.7%
9	House Regulators		624	747	122	19.6%
10	Customer AMR		4	-	(4)	-100.0%
11	Mains		15,346	11,594	(3,751)	-24.4%
12	Measuring & Regulating Equipment		(60)	0	60	-100.2%
13	Meters		1,420	1,180	(240)	-16.9%
14	**Total Distribution Plant**		$ 31,028	$ 25,979	$ (5,049)	-16.3%
	GENERAL PLANT					
15	Structures & Improvements		$ 511	$ 735	$ 224	43.9%
16	Furniture & Office Equipment		27	12	(15)	-56.6%
17	Computer Hardware - 3 yr		301	432	131	43.4%
18	Computer Hardware - 5 yr		57	365	308	538.7%
19	Intangible Computer Software - 3 yr		923	956	33	3.6%
20	Intangible Computer Software - 10 Yr		2,579	19,795	17,216	667.5%
21	Transportation Equipment		815	465	(351)	-43.0%
22	Heavy Work Equipment		213	968	755	354.8%
23	Tools & Work Equipment		242	332	90	37.1%
24	Communications Equipment-Owned		3	8	4	131.4%
25	**Total General Plant**		$ 5,673	$ 24,067	$ 18,395	324.3%
26	**Total Plant In Service**[1]	Sch. 4.1	$ 41,895	$ 55,317	$ 13,421	309.5%

[1] All columns reflect additions from both current year expenditures and CWIP transfers. In previous filings, only additions from current year expenditures were shown.

Guidelines:
(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding
(2) Please add line items as needed to give sufficient understanding of the main capital additions in the reporting year.

SCHEDULE 5

Apex Utilities Inc.
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Actual[1]	2021 Actual[1]	2021 vs. 2020 $	2021 vs. 2020 %
1	Net Income Before Tax		$ 15,357	$ 16,018	$ 661	4.3%
2	Total Permanent Differences		63	69	6	9.0%
3	Total Timing Differences		(9,692)	(16,087)	(6,395)	66.0%
4	Total Differences		(9,629)	(16,018)	(6,389)	66.4%
5	Taxable Income		5,728	-	(5,728)	-100.0%
6	Federal Income Tax Rate		15%	15%		
7	Total Federal Income Tax		859	-		
8	Provincial Income Tax Rate		9%	8%		
9	Total Provincial Income Tax		516	-		
10	Current Tax Payable		1,375	-	(1,375)	-100.0%
11	Large Corporation and Other Tax		-	-	-	0.0%
12	Prior Year (Over)/Under Provisions		15	(133)	(148)	-971.8%
13	Recovery From Loss Carry Back		-	-	-	0.0%
14	Other		-	-	-	0.0%
15	Current Income Tax		1,390	(133)	(1,523)	-109.6%
16	Deferred Income Tax		(181)	172	353	-195.1%
17	**Corporate Income Tax**	Sch. 10	$ 1,209	$ 39	$ (1,170)	-96.8%
					-	
	Income Tax Adjustments				-	
18	Tax on Disallowed O&M		$ -	$ -	$ -	0.0%
19	Other Non-Utility Adjustments		254	(118)	(372)	-146.3%
20	Sub-Total Tax Adjustments	Sch. 10	254	(118)	(372)	-146.3%
21		Sch. 10	1,464	(79)	(1,542)	-105.4%
22	Effect of Normalization	Sch. 10	(212)	20	232	-109.3%
23	**Normalized Utility Income Tax**	Sch. 10	$ 1,251	$ (59)	$ (1,310)	-104.7%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Describe tax methodology (flow through or based on CICA) - Flow through methodology used.

SCHEDULE 5.1

Apex Utilities Inc.
SUMMARY OF DEFERRED INCOME TAX LIABILITY
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Actual[1]	2021 Actual[1]	2021 vs. 2020 $	2021 vs. 2020 %
1	Unfunded Balance		$ 33,752	$ 38,889	5,137	15.2%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.

Guidelines:

(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Describe tax methodology (flow through or based on CICA) - Flow through methodology used.

Apex Utilities Inc.
SUMMARY OF SALES BY CLASSIFICATION
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.		2020 Normalized[1]	2021 Actual		2021 Normalized[1]		2021 Normalized vs. 2020 Normalized #, $	%
	REVENUE CLASSIFICATIONS									
	Residential									
1	Average Customer #			59,435	59,757		59,757		322	0.5%
2	Revenue		$	62,510	72,240	$	72,411	$	9,901	15.8%
	Commercial									
3	Average Customer #			7,458	7,435		7,435		(23)	-0.3%
4	Revenue		$	23,449	27,926	$	28,070	$	4,621	19.7%
	Rural									
5	Average Customer #			14,016	14,018		14,018		2	0.0%
6	Revenue		$	21,455	25,430	$	25,543	$	4,089	19.1%
	Large General Service									
7	Average Customer #			143	141		141		(2)	-1.6%
8	Revenue		$	4,322	4,950	$	5,001	$	679	15.7%
	Irrigation									
9	Average Customer #			138	129		129		(9)	-6.5%
10	Revenue		$	311	390	$	390	$	79	25.3%
	Demand/Commodity									
11	Average Customer #			60	60		60		-	0.0%
12	Revenue		$	4,978	5,760	$	5,760	$	782	15.7%
13	Sub-Total Rate Revenue	Sch. 1	$	117,024	136,695	$	137,175	$	20,151	17.2%
	TRANSPORTATION REVENUE									
	Industrial									
14	Producer		$	132	143	$	143	$	11	8.7%
15	Other Distribution			14	54		54		40	297.0%
16	Other (Please Specify)			-	-		-		-	0.0%
17	Total Transportation Revenue	Sch. 1.1	$	145	197	$	197	$	52	35.6%
18	Total Sales & Transportation		$	117,169	136,892	$	137,372	$	20,203	17.2%
19	Property Tax Revenue		$	-	-	$	-	$	-	0.0%
20	Deficiency	Sch. 1		2,968	(129)		(129)		(3,098)	-104.4%
21	Prior Year Deficiency Adjustments	Sch. 1		24	932		932		908	3850.2%
22	Penalty Revenue	Sch. 1		129	179		179		50	39.1%
23	Sub-Total		$	3,120	981	$	981	$	(2,139)	-68.6%
	OTHER REVENUE									
24	Service Work	Sch. 1.1		231	12		12	$	(220)	-94.9%
25	AER Deposit Interest	Sch. 1.1		4	3		3		(2)	-41.3%
26	Other Revenue	Sch. 1.1		789	1,323		1,323		533	67.6%
27	Sub-Total	Sch. 1.1		1,025	1,337		1,337		312	30.4%
28	**TOTAL NORMALIZED REVENUE**	Sch. 1 & 10		121,315	139,211		139,691	$	18,376	15.1%
	NON-UTILITY REVENUE ADJUSTMENTS									
29	Non-Utility Revenue			-	-		-		-	0.0%
30	Sub-Total			-	-		-		-	0.0%
31	**TOTAL NORMALIZED UTILITY REVENUE**	Sch. 1 & 10	$	121,315	139,211	$	139,691	$	18,376	15.1%

Notes:
1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.
2 Prior year average customer #'s were updated for residential, commercial and rural due to a report error corrected in 2020.

Guidelines:
(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Please use the Revenue category if retail customer classifications do not apply. The customer classification should match the decision.

SCHEDULE 7

Apex Utilities Inc.
EXPLANATION OF TRANSACTIONS WITH AFFILIATED COMPANIES
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Affiliate	Nature of Service	Cross Ref.	2020 Actual	2021 Actual	2021 vs. 2020 $	2021 vs. 2020 %
1	TriSummit Utilities Inc.	Administrative & management services		$ (2,984)	$ (2,753)	$ 231	-7.8%
2		Administrative & management services		465	355	$ (110)	-23.7%
3		Reimbursement of expenses - software group licensing		(270)	(177)	$ 93	-34.4%
4		Foreign exchange contracts		(226)	226	$ 452	-200.0%
5		Other		(54)	(148)	$ (94)	175.4%
6		Sub-Total		$ (3,069)	$ (2,497)	$ 572	-18.6%
7	AltaGas Ltd.	Administrative & management services		$ (8)	$ -	$ 8	-100.0%
8		Natural gas purchases		(8,601)	-	8,601	-100.0%
9		Gas portfolio management & gas operations		(137)	-	137	-100.0%
10		Sub-Total		$ (8,746)	$ -	$ 8,746	-100.0%
11	TriSummit Utility Holdings Inc.	Financing charges from affiliate on notes payable and advances		$ (10,457)	$ (10,550)	$ (93)	0.9%
12		Sub-Total		$ (10,457)	$ (10,550)	$ (93)	0.9%
13	AltaGas Extraction and Transmission LP	Pipeline operating agreement		$ 2	$ -	$ (2)	-100.0%
14		Transportation services		(70)	-	70	-100.0%
15		Sub-Total		$ (68)	$ -	$ 68	-100.0%
16	Heritage Gas Limited	Administrative support services and occasional services		$ 447	$ 505	$ 58	13.0%
17		Reimbursement of expenses related to corporate group of companies' projects		(142)	(111)	31	-21.7%
18		Sub-Total		$ 305	$ 394	$ 89	29.1%
19	Pacific Northern Gas Ltd.	Administrative support services and occasional services		$ 1,411	$ 1,836	$ 424	30.1%
20		Reimbursement of expenses related to corporate group of companies' projects		(678)	(677)	2	-0.2%
21		Sub-Total		$ 733	$ 1,159	$ 424	57.9%
22	**TOTAL**			$ (21,302)	$ (11,494)	$ 9,806	-46.0%

Guidelines:
(1) The services provided or received need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Provide a cross-reference for each item to the relevant schedules where the amounts have been included in this reporting package.
(3) Amounts in this schedule must be reconciled on Schedule 10 to the Audited Financial Statements.
(4) Identify charges in brackets indicating an expense to Apex Utilities Inc.

SCHEDULE 8

Apex Utilities Inc.

SUMMARY OF PAYROLL AND MANPOWER STATISTICS

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross Ref.	2020 Actual	2021 Actual	2021 vs. 2020 $	2021 vs. 2020 %
	Payroll Statistics					
1	Gross Salaries & Wages		$ 28,561	$ 29,309	$ 748	2.6%
2	Gross Employee Benefits		$ 8,559	$ 9,993	$ 1,434	16.8%
	Manpower Statistics (Year-End)					
3	Total Regular Employees (FTEs)		239	240	1	0.3%
4	Total Temporary Employees (FTEs)		10	7	(3)	-30.0%
5	Total Contract Staff (FTEs)		-	-	-	0.0%
6	**Total Manpower**		249	247	(2)	-0.9%
	Less:					
7	Charged to Non-Regulated		-	-	-	0.0%
8	**Total Manpower - Utility Operations**		249	247	(2)	-0.9%
	Manpower Allocation by Division					
9	President		1	1	-	0.0%
10	Vice President		3	3	-	0.0%
11	Director		8	7	(1)	-12.5%
12	Financial Services		49	46	(3)	-6.2%
13	Operations		140	140	-	0.0%
14	Administrative Services		41	43	2	4.9%
15	Regulatory & Legal Affairs		8	8	-	0.0%
16	**Total Manpower - Utility Operations**		249	247	(2)	-0.8%

Notes:

1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.
2 Full Time Equivalents (FTEs) are based upon year end numbers.
3 FTEs are calculated using total regular hours worked divided by standard full time hours (not including overtime).

Guidelines:
(1) Explanations are required for variances exceeding the limits applicable to the Utility based on the following criteria:

Utility Rate Base	Variance Limits
≥$2 billion	$5 million, or 10% and having a $ amount greater than $1 million
≥$1 billion<$2 billion	$2 million, or 10% and having a $ amount greater than $500 K
≥$500 million<$1 billion	$1 million, or 10% and having a $ amount greater than $250 K
≥$100 million<$500 million	$500 K, or 10% and having a $ amount greater than $125 K
≥$25 million<$100 million	$200 K, or 10% and having a $ amount greater than $50 K
<$25 million	$50 K , or 10% and having a $ amount greater than $15 K

(2) Please state if FTE is based on an average or upon year end numbers. This should be consistent with the decision.
(3) Add rows as needed to be consistent with the decision.

Apex Utilities Inc.
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	2020 Actual Opening Balance	2020 Actual Adds	2020 Actual Amort.	2020 Actual Recoveries	2020 Actual Ending Balance	2021 Actual Opening Balance	2021 Actual Adds	2021 Actual Amort.	2021 Actual Recoveries	2021 Actual Ending Balance	2021 vs. 2020 $	2021 vs. 2020 %
	List of Deferral Accounts													
1	Deferred Cost of Gas		$ 971	$ 34,143	$ -	$ 33,351	$ 1,763	$ 1,763	$ 48,148	$ -	$ 47,415	$ 2,496	$ 733	29.4%
2	Deferred Pension Losses - Transition [2]		234	-	117	-	117	117	-	117	-	-	(117)	0.0%
3	AUC Assessment Y Factor		(2)	256	253	-	1	1	250	253	-	(2)	(2)	152.2%
4	UCA Assessment Y Factor		(1)	88	89	-	(2)	(2)	52	72	-	(21)	(19)	92.5%
5	Intervener Y Factor		(32)	68	97	-	(60)	(60)	(39)	(45)	-	(54)	6	-10.8%
6	Production Abandonment Y Factor [3]		386	327	449	-	264	264	8	394	-	(122)	(386)	315.4%
7	NGSSC		(127)	88	-	-	(38)	(38)	62	-	-	24	62	261.6%
8	**Total Regulated Deferrals**		$ 1,430	$ 34,971	$ 1,004	$ 33,351	$ 2,045	$ 2,045	$ 48,480	$ 789	$ 47,415	$ 2,321	$ 275	13.5%

Notes:
1 Refer to Notes 1 & 2, Income Summary, Schedule 10 for an explanation of how Actual and Normalized results are defined.
2 Deferred Pension Losses - Transition account is related to transition to US GAAP
3 Production Abandonment Y Factor was approved within Decision 23898-D01-2018.

Guidelines:
(1) The line items should show sufficient breakdown to allow for reasonable understanding of operations. Please state the source of the approved deferral or reserve.
(2) Please state the regulated reserve and deferral accounts in this schedule.

SCHEDULE 10

Apex Utilities Inc.

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($000s)

Line No.	Description	Cross Ref.	Audited Financial Statements	Adjustments[1]	Utility Total	2021 Normalized[2]	2020 Normalized	2021 Normalized vs. 2020 Normalized $	%
1	**Revenues**		$ 139,248				123,138		
2	2018 Y Factors True-Up from Provision to Filing			-			47		
3	2019 Y and K Factors True-Up from Provision to Filing			-			(251)		
4	2020 Y and K Factors True-Up from Provision to Filing			32			-		
5	Reclass Negative Salvage Depreciation			4,213			3,958		
6	Reclass Cost of Removal			(1,159)			(1,066)		
7	Non-Regulatory Revenue			(846)			(922)		
8	Reclass Property Tax	Sch. 2.5		(2,277)			(2,233)		
9	Weather					479	(1,356)		
10	Other								
11		Sch. 1	$ 139,248	$ (37)	139,211	139,691	121,316	$ 18,375	13.2%
12	**OM&A and Property Taxes**		$ 47,624				47,666		
13	Reclass Property Tax	Sch. 2.5		(2,277)			(2,233)		
14	Reclass Cost of Removal			(1,159)			(1,066)		
15	Reclass Other Net Periodic Pension Costs [3]			(152)			(259)		
16	Other			-			(15)		
	Disallowed and Not-Applied For Expenses								
17	Inter-Affiliate Costs	Sch. 3.0		(616)			(900)		
18	Community Sponsorship	Sch. 3.0		(42)			(21)		
19	STIP	Sch. 3.0		(93)			(68)		
20		Sch. 1	$ 47,624	$ (4,338)	43,286	43,286	43,105	$ 181	0.4%
21	**Cost of Natural Gas**		$ 47,414				33,351		
22	Weather					394	(471)		
23		Sch. 1	$ 47,414	$ -	47,414	47,808	32,880	$ 14,928	31.2%
24	**Foreign Exchange Loss**		$ 59				342		
25	Unrealized (gain) loss on foreign exchange			249			(280)		
26	Foreign exchange (gain) loss			(308)			(62)		
			$ 59	$ (59)	-	-	-	$ -	0.0%
27	**Other Net Periodic Pension Costs [3]**		$ (152)	$ 152			-		
28						-	-		
29			$ (152)	$ 152	-	-	-	$ -	#DIV/0!
30	**Depreciation and Amortization**		$ 17,691				16,162		
31	Reclass Negative Salvage Depreciation			4,213			3,958		
32		Sch. 1 & 4	$ 17,691	$ 4,213	21,904	21,904	20,120	$ 1,783	8.1%
33	**Interest Expense**		$ 10,594				10,519		
34	Financing			338			(151)		
35			$ 10,594	$ 338	10,932	10,932	10,368	$ 564	5.2%
36	**Income Tax**		39				1,209		
37	Revenue Adjustments			(8)			(112)		
38	OM&A and Property Tax Adjustments			998			1,033		
39	Foreign exchange loss			14			82		
40	Other Net Periodic Pension Costs			(35)			-		
41	Depreciation and Amortization			(969)			(950)		
42	Financing Adjustment			(78)			36		
43	Weather, Net					20	(212)		
44	Tax Addbacks & Deductions Adjustments			-			-		
45	Deferred Taxes			(172)			181		
46	Other Tax Adjustments			133			(15)		
47	Loss (Carryback)/Forward			-			-		
48		Sch. 1	$ 39	$ (118)	(79)	(59)	1,251	$ (1,310)	2220%
49	**Return**		$ 15,979		15,755	15,820	13,591	$ 2,229	14.1%

Notes:

1 Utility Return (Col. H) and Actual results assume:
- approved weighted average cost of debt
- deemed capital structure applied to actual rate base
- exclusion of any non-revenue requirement expenses (i.e. disallowed & not applied for expenses)
- exclusion of any non-distribution tariff revenue (e.g. AFUDC)
- exclusion of adjustments for weather variances to normal

For clarification, Adjustments (Col. H) are not non-Utility adjustments. AUI considers all of its financial results are Utility in nature. The Utility column (Col. I) corresponds with Actual results stated in the other schedules within this package.

2 Normalized Return (Col. K) is based on Utility Return and includes an adjustment for weather variances to normal.

3 Effective January 1, 2018, AUI adopted US GAAP Accounting Standards Update No. 2017-07, *Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* The amendments within this ASU revise the presentation of net periodic pension cost and net periodic post-retirement cost on the income statement.

SCHEDULE 11

Apex Utilities Inc.

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021
BALANCE SHEET ITEMS
($000s)

Line No.	Description	Cross Ref.	Audited Financial Statements	Adjustments	Utility Total
	Current Assets				
1	Cash		$ 495	$ -	$ 495
2	Accounts receivable		32,296	-	32,296
3	Pension asset		-	-	-
4	Inventory		301	-	301
5	Prepaid expenses and deposits		2,098	-	2,098
6	Income taxes recoverable		-	-	-
7	Total Current Assets		$ 35,190	$ -	$ 35,190
	Regulatory Current Assets				
8	Deferred cost of gas		$ 2,496	$ -	$ 2,496
9	Deferred property taxes		995	-	995
10	Payment deferral		169		169
11	Total Regulatory Current Assets		$ 3,660	$ -	$ 3,660
	Property Plant and Equipment				
12	Property, plant and equipment at cost		$ 689,195	$ -	$ 689,195
13	Accumulated depreciation		(189,098)	-	(189,098)
14	Contributions in aid of construction (net)		(57,795)		(57,795)
15	Net Property, Plant and Equipment		$ 442,302	$ -	$ 442,302
	Intangible Assets				
16	Intangible assets at cost		$ 43,123	$ -	$ 43,123
17	Accumulated depreciation		(12,673)	-	(12,673)
18	Net Intangible Assets		$ 30,450	$ -	$ 30,450
	Regulatory Non-Current Assets				
19	Deferred tax asset		$ 39,948	$ -	$ 39,948
20	Deferred pension losses - transition		-	-	-
21	Deferred pension losses		8,901	-	8,901
22	Deferred load balancing		62	-	62
23	Payment deferral		-	-	-
24	Deferred Y and K factor costs		45	-	45
25	Total Regulatory Non-Current Assets		$ 48,956	$ -	$ 48,956
	Other Assets				
26	Deposits		$ 556	$ -	$ 556
27	Deferred income tax asset		-	-	-
28	Advances to parent		-	-	-
29	Right-of-use asset - finance		398	-	398
30	Other assets		2,569	-	2,569
31	Total Other Assets		$ 3,523	$ -	$ 3,523
32	**Total Assets**		$ 564,081	$ -	$ 564,081
			-	-	0
	Current Liabilities				
33	Short Term Debt		$ 663	$ -	$ 663
34	Accounts payable		34,732	-	34,732
35	Income Tax Payable		-	-	-
36	Advances from parent		6,690	-	6,690
37	Current portion of long-term debt payable to parent		-	-	-
38	Foreign exchange contracts liability		-	-	-
39	Lease liabilities - finance		37	-	37
40	Lease liabilities - operating		368	-	368
41	Customer deposits		5,232	-	5,232
42	Total Current Liabilities		$ 47,722	$ -	$ 47,722
	Regulatory Current Liabilities				
43	Deferred cost of gas		$ -	$ -	$ -
44	Deferred tax liability		-	-	-
45	Deferred regulatory costs		-	-	-
46	Total Regulatory Current Liabilities		$ -	$ -	$ -
	Non-Current Liabilities				
47	Deferred income tax liability		$ 38,889	$ -	$ 38,889
48	Pension and other post-retirement benefit liabilities		16,242	-	16,242
49	Lease liabilities - finance		365	-	365
50	Lease liabilities - operating		1,849	-	1,849
51	Total Non-Current Liabilities		$ 57,345	$ -	$ 57,345
	Regulatory Non-Current Liabilities				
52	Future removal and site restoration costs		$ 27,898	$ -	$ 27,898
53	Deferred load balancing		-	-	-
54	Deferred regulatory costs		-		-
55	Y and K factor costs		175	-	175
56	Total Regulatory Non-Current Liabilities		$ 28,073	$ -	$ 28,073
	Capital				
57	Long term debt payable to parent		$ 263,000	$ -	$ 263,000
58	Share capital		57,122	-	57,122
59	Retained earnings		112,414	-	112,414
60	Accumulated other comprehensive income (loss)		(1,595)	-	(1,595)
61	Total Capital		$ 430,941	$ -	$ 430,941
62	**Total Liabilities and Capital**		$ 564,081	$ -	$ 564,081

Schedule	Line	Variance	Variance Explanation
1	1	2021 Normal vs. 2020 Normal	Refer to Schedule 2.1 for details of variance in Return on Rate Base.
1	3	2021 Normal vs. 2020 Normal	Refer to Schedule 4 for details of variance in Depreciation and Amortization Expense.
1	4	2021 Normal vs. 2020 Normal	Refer to Schedule 9 for details of variance in Deferral Account Amortization.
1	5	2021 Normal vs. 2020 Normal	Refer to Schedule 5 for details of variance in Income Tax Expense.
1	7/10	2021 Normal vs. 2020 Normal	Increase in Flow Through Expenses is the result of higher natural gas prices and higher volumes in 2021 compared to 2020.
1	9	2021 Normal vs. 2020 Normal	Increase due to higher delivery rates in 2021 compared to 2020 as provided by the PBR formula as well as increased usage.
1	12/13	2021 Normal vs. 2020 Normal	Refer to Schedule 6 for an explanation of the variance in Revenue Deficiency and Excess.
1	15	2021 Normal vs. 2020 Normal	Refer to Schedule 1.1 for an explanation of the variance in Other Revenue.
1.1	1	2021 Normal vs. 2020 Normal	The increase in Other Utility Revenue in 2021 is primarily due to inter-affiliate asset utilization recovery charged for shared services.
1.1	3	2021 Normal vs. 2020 Normal	Decrease due to lower service work completed in 2021 compared to 2020.
1.1	5	2021 Normal vs. 2020 Normal	Increase due to higher inter-affiliate asset utilization recovery in 2021 compared to 2020.
2	1	2021 Actual vs. 2020 Actual	Debt return is higher due to an increase in the Mid-Year Rate Base, and net new issuance of $15MM debt in 2021. Refer to Schedule 2.3 for details of debt issuances in 2021.
2	3	2021 Actual vs. 2020 Actual	The higher non-weather normalized return is primarily due to higher delivery rates provided by the PBR formula and lower income tax expenses offset by fewer degree days in 2021 compared to 2020.

Schedule	Line	Variance	Variance Explanation
2	8	2021 Normal vs. 2020 Normal	Refer to Line 1 above.
2	10	2021 Normal vs. 2020 Normal	The higher weather normalized return is primarily due to higher delivery rates provided by the PBR formula and lower income tax expenses in 2021 compared to 2020.
2.1	2	2021 Normal vs. 2020 Normal	Refer to Schedule 4.2 for Capital Additions variances detail.
2.1	3	2021 Normal vs. 2020 Normal	The increase in retirements is primarily due to higher straight line retirements of intangible software assets compared to the prior year.
2.1	8	2021 Normal vs. 2020 Normal	The decrease in mid-year CWIP is a result of a lower year-end WIP balance in 2021 compared to 2020. The lower balance is primarily related to multi-year software projects initiated in 2019, and completed in 2021.
2.1	13	2021 Normal vs. 2020 Normal	The increase in depreciation expense is due to year-over-year increase in property, plant and equipment balances.
2.1	14	2021 Normal vs. 2020 Normal	Refer to Line 3 above.
2.1	21	2021 Normal vs. 2020 Normal	Increase in Cash Working Capital is primarily due to higher depreciation costs than prior year, no corporate income tax final payment for 2021 compared to the prior year, and higher salaries, wages, and benefits than prior year.
2.1	29	2021 Normal vs. 2020 Normal	Increase is due to year-over-year increase in contributions received in aid of construction resulting from construction activities.
2.1	32	2021 Normal vs. 2020 Normal	Increase in accumulated amortization of CIAC is due to 2021 amortization recognized.
2.2			No variance explanations required.
2.3			No variance explanations required.
2.4			No variance explanations required.
2.5			No variance explanations required.
2.6			No variance explanations required.

Schedule	Line	Variance	Variance Explanation
2.6.1			No variance explanations required.
3	2	2021 Normal vs. 2020 Normal	Decrease is due to lower salaries and wages due to higher capitalization of labour and amounts credited for shared services as well as lower training fees related to general operations work.
3	5	2021 Normal vs. 2020 Normal	Due to higher software and maintenance charges associated with the new Customer Information System implemented in 2021 as well as staff training costs and an increase in temporary operational staffing costs associated with the implementation.
3	9	2021 Normal vs. 2020 Normal	Primarily due to lower contractor charges as a result of a lower volume of meter recalls and related meter repairs experienced in 2021.
3	12	2021 Normal vs. 2020 Normal	Decrease due to lower inter-affiliate costs in 2021 compared to 2020.
4	1	2021 Normalized vs. 2020 Normalized	The increase in depreciation expense is due to year-over-year increase in property, plant and equipment balances.
4	8	2021 Normalized vs. 2020 Normalized	Refer to Line 1 above.
4.1			No variance explanations required.
4.2	3	2021 Actual vs. 2020 Actual	Increase is primarily due to higher expenditures associated with Major Replacement Projects (MRP) Steel pipe, and general pipe replacement projects in 2021 compared to 2020; offset by a reduction in expenditures for gas supply projects (no large scale projects undertaken in 2021).
4.2	5	2021 Actual vs. 2020 Actual	Decrease is primarily due to fewer expenditures associated with MRP station upgrades or refurbishments in 2021 compared to 2020.
4.2	8	2021 Actual vs. 2020 Actual	Decrease is due to fewer expenditures associated with MRP Polyvinyl Chloride (PVC), and Steel pipe replacement projects in 2021 compared to 2020.
4.2	11	2021 Actual vs. 2020 Actual	Decrease is due to fewer expenditures associated with MRP PVC pipe replacement projects in 2021 compared to 2020, partially offset by higher expenditures associated with MRP Non Certified Polyethylene pipe replacement projects.

Schedule	Line	Variance	Variance Explanation
4.2	13	2021 Actual vs. 2020 Actual	Decrease is primarily due to a fewer meter equipment purchases in 2021 compared to 2020, primarily as a result of supply chain issues with manufacturers.
4.2	15	2021 Actual vs. 2020 Actual	Increase is primarily attributable to lifecycle replacement of the roofing structure at Leduc head office in 2021. No similar projects were undertaken in 2020.
4.2	17	2021 Actual vs. 2020 Actual	Increase is primarily attributable to higher expenditures for lifecycle hardware replacement in 2021 compared to 2020.
4.2	18	2021 Actual vs. 2020 Actual	Increase is primarily attributable to higher server and network infrastructure requirements for lifecycle replacement in 2021 compared to 2020.
4.2	20	2021 Actual vs. 2020 Actual	Increase is primarily attributable to multi-year software projects initiated in 2019, and completed in 2021. The largest project completed was the replacement of the Customer Information System.
4.2	21	2021 Actual vs. 2020 Actual	Decrease is primarily due to fewer vehicles and transportation equipment requiring lifecycle replacement in 2021 compared to 2020.
4.2	22	2021 Actual vs. 2020 Actual	Increase is primarily due to more heavy work requiring lifecycle replacement in 2021 compared to 2020.
5	1	2021 Actual vs. 2020 Actual	Increase primarily due to higher delivery rates in 2021 compared to 2020 as provided by the PBR formula as well as increased usage.
5	3	2021 Actual vs. 2020 Actual	Increase due primarily to higher Capital Cost Allowance (CCA) from new Customer Information System being placed in service for 2021.
5	12	2021 Actual vs. 2020 Actual	Prior year adjustment related to loss carryback requested to a taxation year with a higher statutory tax rate resulting an additional recovery.
5	16	2021 Actual vs. 2020 Actual	Deferred tax expense increase due to flow-through tax timing differences.
5	19	2021 Actual vs. 2020 Actual	The variance is a combined effect of the adjustments between the audited financial statements and utility results as shown in Schedule 10 Income Summary.

Schedule	Line	Variance	Variance Explanation
5	22	2021 Actual vs. 2020 Actual	The variance is a combined effect of the weather normalization adjustments between the audited financial statements and normalized results as shown in Schedule 10 Income Summary.
5.1	1	2021 Actual vs. 2020 Actual	Increase due to differences in the tax and accounting basis of capital assets.
6	2	2021 Normal vs. 2020 Normal	Revenue increase is attributed to increase in delivery rates as provided by the PBR formula and higher average price of natural gas in 2021 compared to 2020.
6	4	2021 Normal vs. 2020 Normal	Refer to explanation for Line 2 above.
6	6	2021 Normal vs. 2020 Normal	Refer to explanation for Line 2 above.
6	8	2021 Normal vs. 2020 Normal	Refer to explanation for Line 2 above.
6	12	2021 Normal vs. 2020 Normal	Refer to explanation for Line 2 above.
6	20	2021 Normal vs. 2020 Normal	Variance is primarily due to depreciation study decision (AUC Decision 24161-D03-2019) impact approved for collection in 2020.
6	21	2021 Normal vs. 2020 Normal	Higher due to higher prior year deficiency adjustments collected in 2021 due to regulatory decisions impacting prior year rates.
6	24	2021 Normal vs. 2020 Normal	Decrease due to lower service work completed in 2021 compared to 2020.
6	26	2021 Normal vs. 2020 Normal	Increase due to higher inter-affiliate asset utilization recovery in 2021 compared to 2020.
7	4	2021 Actual vs. 2020 Actual	Decrease due to foreign exchange contracts settled during 2021.

Schedule	Line	Variance	Variance Explanation
7	8	2021 Actual vs. 2020 Actual	Decrease due to AltaGas Ltd. no longer being an affiliate after June 30, 2020.
7	9	2021 Actual vs. 2020 Actual	Decrease due to AltaGas Ltd. no longer being an affiliate after June 30, 2020.
7	19	2021 Actual vs. 2020 Actual	Increase due to services performed by AUI under shared service agreement for software applications.
8	1	2021 Actual vs. 2020 Actual	Gross Salaries and Wages increased in 2021 compared to 2020 mainly due to lower frictional vacancies, and annual salary increases.
8	2	2021 Actual vs. 2020 Actual	Increase in employee benefits is primarily due to higher pension expense in 2021 compared to 2020.
9	1	2021 Actual vs. 2020 Actual	The deferred cost of gas balances are settled monthly in separate gas cost recovery rate applications made to the AUC. Variance from month to month is due to changes in gas cost and timing differences.
9	6	2021 Actual vs. 2020 Actual	Decrease due to lower actual costs incurred in 2021 compared to 2020.
10			No variance explanations required.
11			No variance explanations required.

2021 ANNUAL DEFAULT RATE TARIFF

FINANCIAL AND OPERATIONAL RESULTS

Apex Utilities Inc.
5509 45 Street
Leduc, AB T9E 6T6

May 13, 2022

Apex Utilities Inc.

AUC RULE 005: ANNUAL DEFAULT RATE TARIFF (DRT) FINANCIAL AND OPERATIONAL RESULTS

FOR THE YEAR ENDED DECEMBER 31, 2021

TABLE OF CONTENTS

Purpose of DRT Schedules

Schedule 1 – Revenue by customer class

To provide a detailed revenue breakdown of energy, non-energy and flow-through revenue by customer category relevant to each provider.

Schedule 2 – Sites and energy sales by customer class

To provide a breakdown of the average number of sites and energy sales by customer category relevant to each provider.

Schedule 3 - Energy and operating expenses

To provide a detailed breakdown of expenses associated with the provision of gas services. Expenses are separated into energy related and operating expenses, flow-though, operating and income tax. Provider energy-related expenses are for the purchase of physical natural

SCHEDULE 1

Apex Utilities Inc.
REVENUE BY CUSTOMER CLASS
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	2021 Residential	Commercial	Rural	Large General Service	Demand Service	Irrigation	Non-Specific	Total *
	Revenue:								
1	Energy revenue	$ 17,201	$ 8,095	$ 8,760	$ 1,081	$ 688	$ 152		$ 35,977
	Non-energy revenue								
2	Default Supply Provider Admin. Fees	1,233	133	383	1	0.3	2		1,753
	Flow-through revenue								
3	Distribution Service Revenue	32,583	7,636	12,373	699	315	151		53,756
4	Third Party Transportation Revenue	2,779	1,275	1,407	183	147	60		5,851
5	Special Meter Reading Charges							309	309
6	Penalty Revenue							179	179
7	Total revenue	$ 53,796	$ 17,139	$ 22,923	$ 1,963	$ 1,151	$ 365	$ 488	$ 97,826
	Revenue offsets and other adjustments:								
8	Total revenue offsets and other adjustments								-
9	**Total**								**$ 97,826**

Line No.	Description	2020 Residential	Commercial	Rural	Large General Service	Demand	Irrigation	Non-Specific	Total *
	Revenue:								
1	Energy revenue	$ 11,269	$ 5,355	$ 5,780	$ 746	$ 433	$ 88		$ 23,670
	Non-energy revenue								
2	Default Supply Provider Admin. Fees	1,241	136	380	1	0.3	2		1,761
	Flow-through revenue								
3	Distribution Service Revenue	31,905	7,556	12,046	730	387	154		52,778
4	Third Party Transportation Revenue	2,299	1,032	1,184	151	125	51		4,841
5	Special Meter Reading Charges							224	224
6	Penalty Revenue							129	129
7	Total revenue	$ 46,714	$ 14,079	$ 19,389	$ 1,629	$ 944	$ 295	$ 353	$ 83,403
	Revenue offsets and other adjustments:								
8	Total revenue offsets and other adjustments								-
9	**Total**								**$ 83,403**

Line No.	Line Item Definitions:
1	Energy revenue: revenue associated with the energy charges billed (gas cost flow through rate or gas cost recovery rate) and approved return margin as applicable.
2	Non-energy revenue: revenue associated with administration charges or customer charges (billed at a fixed amount per day or month).
3	Flow-through revenue: revenue associated with the total distribution tariff, transmission tariff, franchise fee, and local access fee charges billed to customers, on behalf of the distribution utility.
4	Third party transportation revenue
5	Special meter reading charges: fees charged by the provider to set up service.
6	Penalty revenue: revenue associated with the collection of late fees charged to accounts when customers do not pay their bills on time.
7	Total: equal to line 1 plus line 2 plus lines 3 through 6.
8	Total revenue offsets and other adjustments.
9	Total: equal to line 7 plus line 8.

SCHEDULE 2

Apex Utilities Inc.
SITES AND ENERGY SALES BY CUSTOMER CLASS
FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	2021 Residential	Commercial	Rural	Large General Service	Demand Service	Irrigation	Total *
1	Sites - average	38,841	4,200	12,071	34	8	118	55,272
2	Energy sales (terajoules)	4,593	2,161	2,337	293	181	39	9,604
3	Energy sales per site (gigajoules per site)	118	515	194	8,625	22,674	332	174
4	Sites as of December 31	37,749	4,098	11,805	33	6	-	53,691

Line No.	Description	2020 Residential	Commercial	Rural	Large General Service	Demand Service	Irrigation	Total *
1	Sites - average	40,374	4,436	12,352	37	9	129	57,337
2	Energy sales (terajoules)	4,757	2,263	2,437	314	187	38	9,998
3	Energy sales per site (gigajoules per site)	118	510	197	8,492	20,785	297	174
4	Sites as of December 31	39,932	4,381	12,284	37	9	-	56,643

* If other customer categories exist, please insert and report each additional customer category in a separate column.

Line No.	Line Item Definitions:
1	Sites - average: number of sites based on monthly average for the calendar year. A “site” is generally defined as being the finest or lowest level of consumption or usage data. A “site” generally represents a meter installation.
2	Energy sales (terajoules): total energy billed for the applicable customer class.
3	Energy sales per site: line 2 multiplied by 1,000 and divided by line 1.

SCHEDULE 3

Apex Utilities Inc.
ENERGY AND OPERATING EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	2021	2020	Variance higher/(lower)	Variance %
	Energy				
1	Gas purchases	$ 35,977	$ 23,670	$ 12,307	52.0%
2	**Flow-through expenses**	$ 60,096	$ 57,972	2,124	3.7%
	Operating expenses (Note)				
3	Credit costs			-	0.0%
4	Billing and customer care			-	0.0%
5	Corporate allocations			-	0.0%
6	Operational and administration costs			-	0.0%
7	Bad debts expense			-	0.0%
8	AUC administration fee			-	0.0%
9	Hearing costs			-	0.0%
10	Default Supply Provider Admin. Fee	1,753	1,761	(7.7)	-0.4%
11	**Income Tax**			-	0.0%
12	Total expenses	**$ 97,826**	**$ 83,403**	**$ 14,423**	**17.3%**

Note The expenses reported above should exclude regulatory disallowances.
A regulatory cost disallowance is a cost incurred by a default supply provider in the course of business, but the Commission specifically disallowed the inclusion of the cost in a rate setting decision or an AUC rule.

Line No. Line Item Definitions:

1 Gas purchases: the cost of physical gas purchased and expensed associated with the gas cost flow through rate or gas cost recovery rate as applicable.

2 Flow-through expenses: consists of Distribution Service Revenue, Third Party Transportation Revenue, Special Meter Reading Charges and Penalty Revenue from Schedule 1.

3 Credit costs: costs associated with collateral requirements (parental guarantee, letter of credit) of trading exchanges or

4 Billing & customer care: costs related to billing, call centre and other customer support functions.

5 Corporate allocations: allocated corporate overhead based on AUC approved methodologies.

6 Operational and administration costs: expenses associated with the management of the DRT, including salaries, consultant fees, and travel expenses.

7 Bad debts expense: the amount of non-collectible accounts receivable associated with DRT billings.

8 AUC administration fee: a fee sufficient to pay for the Commissions's estimated net expenditures associated with carrying out its powers, duties and functions as assessed by the AUC under Rule 025.

9 Hearing costs: costs associated with proceedings for DRT applications that are approved by the Commission.

10 Other: includes all expenses not accounted for in line items above. Please identify.

1.0 INTRODUCTION

Apex Utilities Inc. (AUI) is a fully-integrated natural gas utility and the only regulated natural gas utility in Alberta to perform both gas distribution and default gas supply (DGS) functions. In general, the costs associated with these activities are not tracked separately and, as previously indicated by AUI in comments provided to the Alberta Utilities Commission (AUC, the Commission), AUI has no plans to segregate the gas distribution service from its default gas supply provider operations.

AUI has always been the DGS provider in its service areas and its accounting and information systems reflect this fully integrated approach. As there are no assets specifically assigned to the DGS function, there is no approved DGS-related ROE. The result is revenues equal costs and the DGS-related profit is nil. Consequently, for AUC Rule 005 DRT reporting purposes, DGS revenues are treated as a flow-through. This is consistent with AUI's previous Rule 005 filings.

2.0 VARIANCE EXPLANATIONS AND ADDITIONAL COMMENTS

Schedule 1 – Revenue by Customer Class

1. Revenue in Schedule 1 is based on the following book financial items:

   a. Energy (gas cost recovery rate) revenue
   b. Default supply provider administration fees
   c. Distribution service revenue
   d. Third party transportation rate revenue
   e. Penalty revenue
   f. Special meter reading charges

2. No variance reporting is required for this schedule.

Schedule 2 – Sites and Energy Sales by Customer Class

3. No variance reporting is required for this schedule.

Schedule 3 – Expenses

4. **Line 1 – Gas Purchases:** 2021 gas purchase expense is higher than 2020 by approximately $12.3 million. The increase is primarily attributable to higher natural gas prices in 2021. The amounts on this line equal AUI's energy revenue. However, these are specifically energy-related amounts and have been presented as an energy expense, rather than a flow-through expense.

5. **Line 2 – Flow-through expenses:** 2021 flow-through expenses is higher than 2020 by approximately $2.1 million. The increase is primarily attributable to higher distribution rates in 2021.

6. **Line 10 – Default Supply Provider (DSP) Administration Fee:** The 2021 DSP Administration Fee expense is lower than 2020 by approximately 0.4% or $7,700. This change is insignificant and is largely attributable to the decrease in default supply customers.

Financial Statements

Apex Utilities Inc.

December 31, 2021

Independent auditor's report

To the Shareholder of
Apex Utilities Inc.

Opinion

We have audited the financial statements of **Apex Utilities Inc.** [the "Company"], which comprise the balance sheets as at December 31, 2021 and 2020, and the statements of income, statements of comprehensive income, statements of shareholder's equity and statements of cash flows for the years then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Chartered Professional Accountants

Edmonton, Canada
March 9, 2022

APEX UTILITIES INC.
BALANCE SHEET
As at December 31

($ thousands)

		2021		2020
ASSETS				
Current assets				
Cash	$	495	$	810
Accounts receivable *(notes 4, 5 and 15)*		32,296		22,427
Inventory		301		242
Regulatory assets *(note 9)*		3,660		2,491
Income taxes recoverable *(note 12)*		-		1,398
Prepaid expenses and deposits (*note 15)*		2,098		2,067
		38,850		29,435
Deposits		556		556
Property, plant and equipment *(note 7)*		442,302		421,633
Intangible assets *(note 8)*		30,450		23,973
Regulatory assets *(note 9)*		48,956		60,441
Right-of-use asset – finance *(note 6)*		398		428
Other assets *(note 6)*		2,569		2,422
	$	564,081	$	538,888
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Short-term debt *(note 10)*	$	663	$	616
Advances from parent *(note 10)*		6,690		9,783
Accounts payable and accrued liabilities *(note 15)*		34,732		28,043
Foreign exchange contracts liability *(notes 4 and 15)*		-		226
Lease liabilities – finance *(note 6)*		37		37
Lease liabilities – operating *(note 6)*		368		422
Customer deposits		5,232		2,742
		47,722		41,869
Long-term debt payable to parent *(note 10)*		263,000		248,000
Regulatory liabilities *(note 9)*		28,073		25,421
Deferred income tax liability *(note 12)*		38,889		33,752
Pension and other post-retirement benefit liabilities *(note 14)*		16,242		31,938
Lease liabilities – finance *(note 6)*		365		391
Lease liabilities – operating *(note 6)*		1,849		1,372
		396,140		382,743
Shareholder's equity				
Share capital *(note 11)*		57,122		57,122
Accumulated other comprehensive loss		(1,595)		(2,412)
Retained earnings		112,414		101,435
		167,941		156,145
	$	564,081	$	538,888

Contingencies *(note 16)*
Commitments *(note 17)*

See accompanying notes to the financial statements

Approved by the Board of Directors of Apex Utilities Inc.:

GRAEME FELTHAM, Director

SHAUN TOIVANEN, Director

APEX UTILITIES INC.
STATEMENT OF INCOME
For the year ended December 31

($ thousands)

		2021		2020
REVENUE *(notes 5, 7, 8 and 15)*	$	139,248	$	123,138
EXPENSES				
Cost of natural gas *(notes 9 and 15)*		47,414		33,351
Operating and administrative *(notes 9 and 15)*		47,624		47,666
Amortization *(notes 7 and 8)*		17,691		16,162
		112,729		97,179
Unrealized gain (loss) on foreign exchange *(notes 4 and 15)*		249		(280)
Foreign exchange loss		(308)		(62)
Operating income		26,460		25,617
Other net pension gain*(note 14)*		(152)		(259)
Interest expense *(note 15)*		10,594		10,519
Income before income taxes		16,018		15,357
Income tax expense (recovery) *(note 12)*				
Current		(133)		1,390
Deferred		172		(181)
		39		1,209
Net income	$	15,979	$	14,148

See accompanying notes to the financial statements

APEX UTILITIES INC.
STATEMENT OF COMPREHENSIVE INCOME
For the year ended December 31

($ thousands)

		2021		2020
Net income	$	15,979	$	14,148
Other comprehensive income (loss), net of tax				
Net gain (loss) from other post-retirement benefit plans, net of income tax expense of $244 (2020 – recovery of $474)		817		(1,585)
Comprehensive income	$	16,796	$	12,563

See accompanying notes to the financial statements

APEX UTILITIES INC.
STATEMENT OF SHAREHOLDER'S EQUITY
For the year ended December 31

($ thousands)

	2021	2020
Common shares, beginning of year	$ 57,122	$ 57,122
Common shares issued during the year *(note 11)*	-	-
Common shares, end of year	57,122	57,122
Retained earnings, beginning of year	101,435	94,287
Net income	15,979	14,148
Dividends declared	(5,000)	(7,000)
Retained earnings, end of year	112,414	101,435
Accumulated other comprehensive loss, beginning of year	(2,412)	(827)
Net gain (loss) from other post-retirement benefit plans	817	(1,585)
Accumulated other comprehensive loss, end of year	(1,595)	(2,412)
Shareholder's equity	$ 167,941	$ 156,145

See accompanying notes to the financial statements

APEX UTILITIES INC.
STATEMENT OF CASH FLOWS
For the year ended December 31

($ thousands)

		2021		2020
OPERATING ACTIVITIES				
Net income	$	15,979	$	14,148
Items not involving cash:				
Allowance for funds used during construction *(notes 7 and 8)*		(790)		(863)
Amortization *(notes 7 and 8)*		17,784		16,256
Net change in regulatory assets and liabilities		17,690		(2,767)
Deferred income taxes		172		(181)
Net change in pension and other post-retirement obligations		(14,634)		4,733
Unrealized loss (gain) on foreign exchange contracts *(note 4)*		(226)		226
Net change in non-cash working capital balances related to operations *(note 13)*		101		5,829
		36,076		37,381
INVESTING ACTIVITIES				
Cash invested in property, plant and equipment *(note 13)*		(36,210)		(38,599)
Cash received as contributions in aid of construction *(note 13)*		2,280		713
Proceeds on disposal of property, plant and equipment		176		153
Cash invested in intangible assets *(note 13)*		(9,566)		(9,900)
		(43,320)		(47,633)
FINANCING ACTIVITIES				
Net change in short-term debt		48		48
Advances from parent		(3,093)		8,014
Long-term debt issued from parent *(note 10)*		15,000		30,000
Long-term debt repaid to parent *(note 10)*		-		(20,000)
Finance lease payments		(26)		(34)
Dividends paid		(5,000)		(7,000)
		6,929		11,028
Net change in cash during the year		(315)		776
Cash, beginning of year		810		34
Cash, end of year	$	495	$	810

See accompanying notes to the financial statements

1. STRUCTURE AND NATURE OF OPERATIONS

Apex Utilities Inc. (formerly AltaGas Utilities Inc.) is a rate-regulated natural gas distribution utility serving residential, farm, commercial, and industrial users in communities and rural areas throughout Alberta. Apex Utilities Inc. (the Company or AUI) is incorporated under the laws of Canada and is a wholly owned subsidiary of TriSummit Utility Holdings Inc. (TUHI), which is an indirect wholly owned subsidiary of TriSummit Utilities Inc. (TSU).

On March 31, 2020, TSU (formerly AltaGas Canada Inc.), the Public Sector Pension Investment Board (PSP Investments) and the Alberta Teachers' Retirement Fund Board (ATRF) announced the completion of the acquisition of all of the outstanding common shares of TSU by TriSummit Cycle Inc. (formerly PSPIB Cycle Investments Inc.) (the Purchaser), a company in which PSP Investments indirectly holds a majority economic interest and ATRF indirectly holds a minority economic interest, in an all-cash transaction pursuant to a plan of arrangement (the Arrangement). The Purchaser acquired each common share of TSU and TSU is now a wholly owned subsidiary of the Purchaser. In connection with the completion of the Arrangement, AltaGas Canada Inc. changed its name to TriSummit Utilities Inc.

On November 6, 2020, AltaGas Utilities Inc. amended its articles of incorporation under Section 178 of the *Canada Business Corporations Act* to change its corporate name from AltaGas Utilities Inc. to Apex Utilities Inc. On December 7, 2020, the Alberta Utilities Commission (AUC) issued a Name Change order to AUI pursuant to Section 8 of the *Alberta Utilities Commission Act*.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The financial statements of the Company are prepared by management in accordance with United States generally accepted accounting principles (US GAAP), including accounting policies reflective of the regulations and decisions of the AUC. The Company received approval from the AUC to adopt US GAAP effective January 1, 2012 within Decision 2012-091 issued April 9, 2012.

Pursuant to National Instrument 52-107, *Acceptable Accounting Principles and Auditing Standards* (NI 52-107), US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under United States securities laws. However, given that TSU is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, TSU sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2024; the date on which TSU ceases to have activities subject to rate regulation; or the effective date prescribed for a mandatory application of International Financial Reporting Standards for rate-regulated accounting.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

Regulation

The Company is engaged in the delivery and sale of natural gas in various communities located within the Province of Alberta and is regulated by the AUC. The AUC exercises statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the regulator, the timing of recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

The Company records the impact of regulatory decisions against management's expected estimates in the period in which decisions are rendered.

For a description of the principal financial statement effects of rate regulation, see note 3; for disclosure of the amounts of the principal financial statement effects of rate regulation, see note 9.

Cash

Cash consists of cash on hand and balances with banks.

Accounts Receivable

Accounts receivable are recorded net of an allowance for doubtful accounts on the balance sheet. The Company regularly analyzes and evaluates the collectability of its accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory of pipe, fittings and other materials used in maintenance activities is valued at the lower of average cost and net realizable value. Cost of inventory is assigned using weighted average cost.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost, including certain overhead, administrative and amortization expenses attributable to construction and an imputed carrying cost incurred during the construction period to finance long-term construction projects as approved by the regulating authorities. The Company capitalizes an imputed carrying cost on assets during construction as authorized by the AUC and the amount capitalized is disclosed in note 7 to the financial statements as allowance for funds used during construction (AFUDC). AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction. It is calculated as the mid-year cost of construction work-in-progress multiplied by the regulated percentage cost of capital. Capitalized overhead, administrative expenses, amortization expense and AFUDC are included in the cost of the related assets and are expected to be recovered in rates charged to customers in future periods through amortization charges.

Additions to property, plant and equipment are sometimes made with the assistance of contributions in aid of construction (CIAC) from the provincial government and customers, where the estimated revenue is less than the cost of providing service or where special facilities are required to supply customers' specific needs. CIAC is recorded as a reduction of the corresponding asset balances. Amortization of CIAC is provided at rates that correspond with the amortization of the related asset and is offset against the accumulated amortization of the corresponding asset.

Revenue from the collection of future removal and site restoration costs in rates is deferred as non-current regulatory liabilities until costs are incurred.

Amortization of the cost, net of salvage value, of property, plant and equipment is provided, subject to the approval of the AUC, on a straight-line basis over the useful life of the asset or over the contract term of a specific agreement related to service to which the assets are dedicated. Amortization rates are subject to periodic review and revision as part of the rate-setting process. Any change in amortization rates affects current and future years' amortization expense and the amount that can be recovered by the Company in its revenue.

2021 and 2020 rates are as follows:

	2021	2020
Transmission and distribution systems	1.33 to 20.00 percent	1.33 to 20.00 percent
Buildings, equipment and administrative	1.54 to 38.27 percent	1.54 to 38.27 percent

The Company's natural gas transmission and distribution network comprises mains, service lines and measuring and regulating equipment and facilities.

The range of useful lives for the Company's property, plant and equipment is 3 to 75 years.

Property, plant and equipment are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment is recognized in the statement of income when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Generally, upon retirement of amortizable assets, accumulated amortization is charged with the cost of the retired unit less salvage value as required by the AUC. As such, no gain or loss is recorded in income. It is expected that any gain or loss that is charged to accumulated amortization will be reflected in future amortization expense when it is collected or refunded in rates. Under US GAAP for entities not subject to rate regulation, differences between the proceeds on disposal and the asset's net book value would be recognized as a gain or loss during the period of disposal.

Intangible Assets

Intangible assets are finite-life assets consisting of computer software, land rights and franchise consents. Intangible assets with finite lives are recorded at cost, including certain overhead and administrative expenses attributable to development and an imputed carrying cost incurred during the development period to finance long-term development projects as approved by the AUC. The Company capitalizes an imputed carrying cost on assets during development as authorized by the AUC and the amount capitalized is disclosed in notes 7 and 8 to the financial statements as AFUDC. Capitalized overhead, administrative expenses and AFUDC included in the cost of the related assets are expected to be recovered in rates charged to customers in future periods through amortization charges.

Amortization of intangible assets with finite lives is provided, subject to the approval of the AUC, on a straight-line basis over the useful life of the asset or over the contract term of a specific agreement related to the service to which those assets are dedicated. Amortization rates are subject to periodic review and revision as part of the rate-setting process. Any change in amortization rates affects the current year's amortization expense and the amount that can be recovered by the Company in its revenue.

2021 and 2020 rates are as follows:

	2021	2020
Computer software	10.00 to 39.28 percent	10.00 to 39.28 percent
Land rights	1.58 to 1.82 percent	1.58 to 1.82 percent
Franchises and consents	10.90 percent	10.90 percent

The range of useful lives for the Company's intangible assets is as follows:

Computer software	3 to 10 years
Land rights	65 to 70 years

Intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of intangible assets with finite lives is recognized in the statement of income when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Generally, upon retirement of amortizable assets, accumulated amortization is charged with the cost of the retired unit less salvage value as required by the AUC. As such, no gain or loss is recorded in income. It is expected that any gain or loss that is charged to accumulated amortization will be reflected in future amortization expense when it is collected or refunded in rates. Under US GAAP for entities not subject to rate regulation, differences between the proceeds on disposal and the asset's net book value would be recognized as a gain or loss in the period of disposal.

Asset Retirement Obligations

Certain of the Company's long-lived tangible assets will have future legal obligations on retirement. However, the Company has not recorded an asset retirement obligation due to the indeterminate life of its transmission and distribution systems and corresponding indeterminable timing and scope of asset retirements. An asset retirement obligation and offsetting capital asset will be recognized when the timing and amount can be reasonably estimated.

Leases – Lessee

An arrangement contains a lease when such arrangement conveys the right to control the use of an identified asset. The Company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which consists of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, less any lease incentives received and any initial direct costs incurred by the lessee. The lease liability is initially measured at the present value of the lease payments that are not yet paid at the commencement date, discounted using the interest rate implicit in the lease or if that cannot be readily determined, the Company's incremental borrowing rate. Lease payments include fixed payments defined by the underlying lease agreements. The Company has elected the practical expedient to not separate lease and non-lease components for its office and equipment leases.

Financial Instruments

A financial instrument is a contract that gives rise to a financial asset of one contract party and a financial liability or equity instrument of another party. Financial instruments are recognized on the balance sheet when the Company becomes party to the contractual provisions of the financial instrument. Financial assets and financial liabilities are initially recognized at fair value.

The Company's financial instruments are classified as follows:

- Accounts receivable are classified as "loans and receivables". Measurements made subsequent to initial recognition are recorded at amortized cost using the effective interest method;
- Prepaid expenses and deposits are classified as "other financial assets". Measurements made subsequent to initial recognition are recorded at amortized cost using the effective interest method;
- Short-term debt, advances from parent, accounts payable and accrued liabilities, long-term debt payable to parent, and customer deposits are classified as "other financial liabilities". Measurements made subsequent to initial recognition are recorded at amortized cost using the effective interest method; and
- Foreign exchange contracts liability are classified as "held-for-trading financial assets or liabilities." These contracts are initially recorded at their fair value, with subsequent changes in fair value recorded in net income under "unrealized gain (loss) on foreign exchange."

All interest expense related to financial instruments is recorded on the statement of income as interest expense.

Revenue Recognition

Revenue includes revenue from the distribution of natural gas and recovery of the cost of gas paid to suppliers, third-party transporters, and associated gas supply costs. The Company recognizes revenue when gas has been delivered or services have been performed. Gas distribution revenue is recorded on the basis of regular customer meter readings and estimates of customer usage since the last meter reading to the end of the reporting period. Revenue is recognized in respect of the Company's fiscal year in a manner that is consistent with the underlying rate-setting mechanism mandated by the regulator. Specifically, for a fiscal year where a rate application has been filed, but no regulatory decision has been issued, the Company records an accrued revenue deficiency equivalent to the difference between the revenue requirement expected to be received under its proposed rate application and the sales revenue recorded at the regulator approved tariff. When the regulator issues a decision respecting the rate application, the Company finalizes its accrued revenue deficiency based on the approved revenue requirement and the revenue charged at the previously approved tariffs. The Company collects or refunds the accrued revenue deficiency by way of a deficiency rate rider over a period or subsequent rate application subject to direction by the regulator. The accrued revenue deficiency is included in accounts receivable and negative deficiency is included in accounts payable and accrued liabilities.

Cost of Natural Gas Sales and Third-party Transportation

Cost of natural gas sales included in distribution tariffs is based on the forecast cost of natural gas and third-party transportation. Variances between forecast and actual costs are deferred for refund to, or collection from, customers through adjustments to future rates in the following month. Such amounts are accumulated in a deferred gas account that is recorded as a regulatory asset or liability on the balance sheet.

Pension and Other Post-retirement Benefit Plans

The Company recognizes the overfunded or underfunded status of its pension and other post-retirement benefit plans as either assets or liabilities on the balance sheet.

The cost of the defined benefit pension and other post-retirement benefit plans is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and other cost escalation and actuarial factors. The current service cost is the sum of the individual current service components, and the projected benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The measurement date for the plan assets and obligations coincides with the fiscal year-end date of December 31. Obligations are attributed to the period beginning on the employee's date of joining the plan and ending on the earlier of the date of termination, death or retirement.

The cumulative unamortized net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the projected benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. However, when all, or almost all, of the employees expected to receive benefits under the plan are no longer active, the amortization period used for unamortized net actuarial gains and losses is the average remaining life expectancy of the former employees. The average remaining service periods of the active members covered by the pension and other post-retirement benefit plans are 16.2 and 15.7 years, respectively.

As a result of regulatory accounting, net actuarial gains and losses associated with the Company's pension plans, excluding other post-retirement benefit plans, are recorded as a regulatory asset and amortized over the same period as the corresponding actuarial gains and losses. Actuarial gains/losses associated with the Company's other post-retirement benefit plans are recorded in other comprehensive income (loss).

The other post-retirement benefit plans are funded on a cash basis as benefits are paid. No assets have been segregated or restricted to provide for the cost of the other benefits.

Income Taxes

Income taxes are calculated using the liability method of tax accounting. Under this method, deferred income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the enacted tax rates and tax laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.

In accordance with Accounting Standards Codification (ASC) 980, *Regulated Operations* (ASC 980), the Company recognizes a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future rates and recovered from or paid to future customers.

Uncertain Tax Positions

The Company recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxation authorities based on the technical merits of the position. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxation authorities. Management reviewed all open tax returns and determined that no provisions were required for uncertainty regarding income taxes.

Foreign Currency Translation

These financial statements are presented in Canadian dollars. Monetary assets and liabilities denominated in a foreign currency are converted to the functional currency (Canadian dollars) using the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the statement of income. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

Use of Accounting Judgments, Estimates and Assumptions

The preparation of financial statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses for the reporting period. Actual results may vary from management's estimates and such variances may be material. The material estimates in these financial statements include the nature and timing of satisfaction of performance obligations for revenue recognition, unbilled natural gas deliveries, regulatory assets and liabilities, useful lives of property, plant and equipment, useful lives of intangible assets, lease terms, discount rate, lease classification, asset retirement obligations and pension and other post-retirement benefits.

Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty involved in making estimates, these estimates are subject to measurement uncertainty and may materially impact the financial statements of future periods.

Adoption of New Accounting Standards

Effective January 1, 2021, the Company adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2019-12, *Income Taxes (Topic 740) Simplifying the Accounting for Income Taxes*. The amendments in this ASU remove certain exceptions and provide some simplifications in accounting for income taxes. The adoption of this ASU did not have a material impact on the Company's financial statements.

- ASU No. 2020-01, *Investments – Equity Securities (Topic 321), Investments – Equity Method and Joint Ventures (Topic 323) and Derivatives and Hedging (Topic 815) – Clarifying the Interactions between Topic 321, Topic 323, and Topic 815*. The amendments in this ASU provide guidance for accounting for certain equity securities when the equity method of accounting is applied or discontinued and for forward contracts and purchased options on certain securities. The adoption of this ASU did not have a material impact on the Company's financial statements.

Future Changes in Accounting Principles

In June 2016, FASB issued ASU No. 2016-13, *Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments*. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. In November 2019, FASB issued ASU No. 2019-10, *Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815) and Leases (Topic 842): Effective Dates,* which deferred the effective date of ASU No. 2016-13 to January 1, 2023. Early adoption is permitted. AUI is currently completing its assessment of the impact of these ASUs on its financial statements.

Reclassification of Prior Year Presentation

Certain prior year amounts have been reclassified for consistency with the current year presentation for comparative purposes. As a result of the reclassification, $2.7 million of customer deposits was reclassified to current liabilities on the balance sheet as at December 31, 2020.

3. FINANCIAL STATEMENT EFFECTS OF REGULATION

The Company accounts for certain transactions in accordance with applicable regulations promulgated by the AUC (regulatory accounting). Such accounting treatment may be different than it would be in the absence of rate regulation, namely the timing of recognition of certain assets, liabilities, revenue and expenses. This results in the creation of regulatory assets and liabilities.

Through the rate-setting process, certain expenses and credits are deferred as assets and liabilities on the balance sheet until the time they are recovered from or refunded to customers. Regulatory assets represent future revenue associated with certain costs incurred in the current period or in prior periods that will be recovered from customers in future periods. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are to be refunded to customers.

When the regulator issues a decision affecting the financial statements, the effects of the decision are recorded in the period in which the decision is received. However, if in management’s judgment a reasonable estimate can be made regarding the impact an impending future decision will have on the current year’s financial statements, an estimate will be recorded in the current year for the expected impact. There is risk and uncertainty that the regulator may not allow full recovery of recorded regulatory assets.

Performance-based Regulation

AUI’s annual rates are set by the AUC using a revenue per customer cap performance-based regulation (PBR) methodology. The Company is currently in its second five-year PBR term from 2018 to 2022. The first PBR term was from 2013 to 2017. The base year of the first PBR term was the 2012 test year of AUI’s 2010 – 2012 General Rate Application.

The base or starting point for PBR was traditional cost of service regulation (COSR) whereby the AUC established the Company’s revenue requirement based on the cost of service associated with operation of the distribution utility and provided a return on rate base. Under COSR, the Company’s return on rate base is equal to the sum of (a) its net rate base multiplied by the allowed equity component multiplied by the regulator-allowed rate of return on equity, plus (b) its net rate base multiplied by the allowed debt component multiplied by the regulator-allowed rate for debt. The gross rate base is the aggregate of the Company’s regulator-approved investments in property, plant and equipment and intangible assets, less accumulated amortization, plus an allowance for working capital. The net rate base excludes from the gross rate base, among other things, no-cost capital, which consists of unamortized CIAC and grants from government and customers. The Company’s allowed equity component is the portion of the Company’s capital structure that the regulator has deemed to be financed with equity for tariff purposes.

In August 2018, the AUC issued Decision 22570-D01-2018, *2018 Generic Cost of Capital*. The orders in this Decision set the final approved return on equity (ROE) for the Company at 8.5 percent per annum for 2018, 2019 and 2020. The AUC had previously set the ROE on an interim basis at 8.5 percent per annum for 2018 and subsequent years. The Company’s regulated capital structure was amended in this Decision to 61 percent debt and 39 percent equity for 2018, 2019 and 2020. On October 13, 2020, the AUC issued Decision 24110-D01-2020 to extend the 2020 Generic Cost of Capital parameters to 2021 for the full year to maintain prospectivity given the ongoing COVID-19 pandemic and related economic and financial market uncertainty and volatility. On March 4, 2021, the AUC issued Decision 26212-D01-2021 to extend the 2020 Generic Cost of Capital parameters to 2022 on a final basis given the continued unsettled nature of capital markets.

The PBR methodology adjusts revenue, and consequently rates, annually. Base revenue is adjusted annually by escalating base revenue per customer from the previous year by an inflation factor (“I”) less a productivity improvements factor (“X”) and applying the escalated revenue per customer amounts to the forecast number of customers for the upcoming year.

In addition to base revenue, the PBR plan includes mechanisms for the recovery of items determined to flow through directly to the customers (“Y” factor), recovery of items related to material unforeseen events (“Z” factor) and the recovery of costs related to capital expenditures that are not being recovered through the inflationary factor of the formula (“K” factor or capital tracker). The AUC also included a PBR re-opener mechanism that allows an application to be re-opened in order to address specific problems with design or operation of the PBR plan after certain thresholds are exceeded that may have a material impact on either a utility or its customers that cannot be addressed through other features of the PBR plan.

In December 2016, the AUC issued Decision 20414-D01-2016, *2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities*, and in February 2018, Decision 22394-D01-2018, *Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities*, establishing parameters for the next generation PBR plans for the five-year period from 2018 to 2022. Under this plan, revenue continues to be set by formula wherein base rates are determined based on a notional 2017 revenue requirement and adjusted each year by customer growth factor (“Q”) and I less X. The 2017 notional revenue requirement was to be established using actual cost data from the preceding PBR term as a basis. In addition, the amount of incremental capital funding available from the base formula is divided into two categories. The first category uses a modified capital tracker with narrow eligibility criteria while the second category uses a newly introduced K-bar mechanism. Under the K-bar mechanism, an annual K-bar amount is established in 2018 by comparing capital revenue requirements available in 2018 through the base formula to notional 2018 capital revenue requirements, which determines a capital funding shortfall or surplus. In each subsequent year of the next generation PBR term, the calculation is repeated to determine the respective year’s shortfall or surplus.

The next generation PBR plan continues to include a Y factor and Z factor. There are no changes to the PBR re-opener mechanism that allows an application to be re-opened in order to address specific problems with design or operation of the PBR plan after certain thresholds are exceeded that may have a material impact on either a utility or its customers that cannot be addressed through other features of the PBR plan.

Regulatory Process – Gas Cost Recovery Rate (GCRR) and Third-party Transportation Rate (TPTR)

The GCRR is charged to consumers for default gas supply, which is the rate-regulated supply choice, and is designed to allow the Company to recover the market-determined price paid for natural gas without any mark-up. The regulator has established a framework for the Company to file its costs monthly with the regulator. The regulator reviews the Company’s GCRR applications to ensure that only the actual cost of gas is passed on to consumers. Once verified by the regulator, interested parties have 30 days to file any objections to the rate.

The Company establishes what its GCRR should be each month by forecasting consumption. The forecast price is then determined using published indices. In addition to gas purchases, the GCRR includes estimated gas supply-related management and administration costs that are incurred by the Company, such as transportation costs, gas supply-related bad debts and gas supply-related cash working capital costs.

During the course of the month, energy costs may vary from the forecast because of changes in demand and market price. In order to reconcile what customers are charged through the cost of gas rate with actual gas costs, any surpluses or deficits are accumulated in a deferred gas account. Any balance in the deferred gas account at the end of a month is included when determining the cost of gas for a subsequent period.

The TPTR is designed to allow the Company to recover third-party gas transportation services costs without any mark-up and is administered the same as the GCRR. The TPTR applies to customers buying retail gas supply, which is the non-regulated gas supplied by competitive retailers, as well as customers buying default gas supply, since third-party transportation is required by all customers.

4. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company’s financial instruments consist of accounts receivable, prepaid expenses and deposits, foreign exchange contracts liability, accounts payable and accrued liabilities, short-term debt, advances from parent, customer deposits, and long-term debt payable to parent.

Level 1 – Fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used.

Level 2 – Fair values are determined based on valuation models and techniques where inputs other than quoted prices included within Level 1 are observable for the asset or liability either directly or indirectly. The Company uses derivative instruments to manage fluctuations in foreign exchange rates. The Company estimates forward prices based on published sources.

Level 3 – Fair values are based on inputs for the asset or liability that are not based on observable market data. The Company uses valuation techniques when observable market data is not available.

The carrying value of accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, short-term debt, advances from parent and customer deposits approximates their fair value due to their short period to maturity. The fair value of long-term debt payable to parent cannot be measured reliably since the Company has no debt rating, the long-term debt is unsecured and contains no early redemption provisions, and no active market for the long-term debt exists.

The Company manages risk and risk exposures through a combination of internal and disclosure controls and sound business practices.

December 31, 2021	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**	**Total fair value**
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -

December 31, 2020	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**	**Total fair value**
Financial liabilities					
Fair value through net income					
Foreign exchange contracts liability	$ 226	$ -	$ 226	$ -	$ 226
Total	$ 226	$ -	$ 226	$ -	$ 226

Credit and Liquidity Risks

Financial instruments that subject the Company to credit risk consist primarily of trade receivables. As at December 31, 2021, the Company had $0.9 million (2020 - $2.0 million) of trade receivables past due that were aged as follows:

($ thousands)

	2021	**2020**
31–60 days	$ 163	$ 1,199
61–90 days	197	318
91+ days	576	473
	$ 936	$ 1,990

The Company provides an allowance for credit losses that is calculated by applying an estimated uncollectible percentage based on historical collection experience to past due trade receivables. As at December 31, 2021, the Company allowed for $0.7 million (2020 - $1.0 million) of past due trade receivables. Individual account balances are considered impaired and recovered through the GCRR or expensed as bad debts when the Company's internal collection efforts were unsuccessful and the accounts have been transferred to an external collections agency. A reconciliation of the allowance account for the years ended December 31 is as follows:

($ thousands)

	2021	**2020**
Balance, beginning of year	$ 1,014	$ 326
Trade receivable accounts written off, net of recoveries	(1,027)	(117)
Bad debts recovered through the GCRR	353	324
Increase to allowance expensed through operating and administrative expenses	344	481
Balance, end of year	$ 684	$ 1,014

Trade receivables credit risk is reduced due to a large and diversified customer base, customer deposits for at-risk customers with a carrying value of $5.2 million (2020 - $2.7 million) and the ability to recover the majority of uncollectible accounts through future customer rates.

The Company has a concentration of credit risk due to the distribution service billings to its retailers or counterparties. Credit risk is the financial risk associated with the non-performance of contractual obligations by counterparties. The Company extends credit to select counterparties in the normal course of business.

For accounts receivable, the Company's credit risk exposure is equal to the carrying value on the balance sheet. The Company monitors its credit exposure in accordance with the Terms and Conditions of Distribution Access Service as approved by the AUC. The Company is required to minimize its net exposure to retailer billings by obtaining an acceptable form of prudential, which includes a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating. As at December 31, 2021, the total amount of prudentials held was $9.7 million.

Foreign Exchange Risk

The Company has entered into foreign exchange forward contracts to manage the risk of fluctuations in the cost of a long-term software implementation agreement as a result of changes in foreign exchange rates. As at December 31, 2021, the Company had outstanding foreign exchange forward contracts of $nil (2020 - US$2.6 million) at a rate of $1.36 Canadian per U.S. dollar.

5. REVENUE

Revenue disaggregated by major sources was as follows:

($ thousands)

	2021	2020
Revenue from contracts with customers		
Gas sales and transportation services	$ 139,248	$ 120,824
Other	1,021	658
Total revenue from contracts with customers	140,269	121,482
Revenue (loss) from other sources	(1,021)	1,656
Total revenue	$ 139,248	$ 123,138

The vast majority of customer contracts have a term of one month; however, there are certain contracts that have terms of one year or longer. For these long-term contracts, there is generally a contract demand specified in the contract whereby the customer has to pay regardless if gas has been delivered. These contracts generally do not contain any make-up rights, and revenue is recognized on a monthly basis as service has been performed.

Accounts receivable as at December 31, 2021 include unbilled receivables of $15.5 million (2020-$9.7 million) related to gas sales and transportation services rendered to customers but not billed at year-end.

6. LEASES

The Company's operating leases include building, equipment and land leases and the Company's finance leases include an equipment lease.

	2021	2020
Weighted average remaining lease term (years)		
Operating leases	31.8	38
Finance leases	12.9	13.9
Weighted average discount rate (%)		
Operating leases	4.11	4.37
Finance leases	2.89	2.89

As at December 31, 2021, the Company had the following future minimum lease payments:

($ thousands)

	Operating	Finance
2022	$ 375	$ 37
2023	363	37
2024	263	37
2025	75	37
2026	75	37
Thereafter	3,158	293
Total undiscounted lease liabilities	4,309	478
Less: Imputed interest	(2,092)	(76)
Present value of lease liabilities	2,217	402
Less: current lease liability	(368)	(37)
Long-term lease liabilities	$ 1,849	$ 365

($ thousands)

As at		2021		2020
Operating Leases	$		$	
Right-of-use assets [(a)]		2,217		1,794
Current lease liability		368		422
Long-term lease liability		1,849		1,372
Total operating lease liability		2,217		1,794
Finance Leases				
Right-of-use assets	$	398	$	428
Current lease liability		37		37
Long-term lease liability		365		391
Total finance lease liability		402		428
Total lease liability	$	2,619	$	2,222

(a) Included under the line item "Other long-term assets" on the balance sheet

The following table summarizes the lease expense recognized in the statement of income:

($ thousands)

		2021		2020
Operating lease cost	$		$	
Operating leases		510		533
Short-term leases		155		154
Total operating lease cost		665		687
Finance lease cost				
Amortization of right-of-use assets	$	31	$	31
Interest on lease liabilities		12		12
Total finance lease cost		43		43
Total lease cost	$	708	$	730

The following table provides supplemental information related to leases:

($ thousands)

		2021		2020
Cash paid for lease amounts included in the measurement of lease liabilities:				
Operating cash flows used for operating leases	$	510	$	533
Operating cash flows used for finance leases		12		12
Financing cash flows used for finance leases		(37)		(37)
Right-of-use assets obtained in exchange for new lease liabilities:				
Operating leases	$	(841)	$	(27)

7. PROPERTY, PLANT AND EQUIPMENT

($ thousands)

				2021								2020
		Cost		Accumulated amortization		Net book value		Cost		Accumulated amortization		Net book value
Transmission and distribution systems	$	526,821	$	115,247	$	411,574	$	496,576	$	105,785	$	390,791
Buildings, equipment and administrative		52,690		21,962		30,728		51,157		20,315		30,842
	$	579,511	$	137,209	$	442,302	$	547,733	$	126,100	$	421,633

Included in property, plant and equipment as at December 31, 2021 was work-in-progress in the amount of $6.4 million (2020 - $4.4 million) and land in the amount of $2.1 million (2020 - $2.1 million) that were not amortized.

The Company recognized $13.9 million of aggregate amortization expense related to property, plant and equipment during 2021 (2020 - $13.3 million).

The Company capitalized $0.3 million of AFUDC during 2021 (2020 - $0.3 million) to property, plant and equipment. The offset to capitalized AFUDC was recognized as revenue.

Contributions in aid of construction of $1.5 million was recorded as a reduction of cost during 2021 (2020 - $2.0 million).

8. INTANGIBLE ASSETS

($ thousands)

			2021			**2020**
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Computer software	$ 37,760	$ 10,233	$ 27,527	$ 33,233	$ 12,268	$ 20,965
Land rights	5,091	2,168	2,923	5,091	2,083	3,008
Franchise consents	272	272	-	272	272	-
	$ 43,123	$ 12,673	$ 30,450	$ 38,596	$ 14,623	$ 23,973

Included in intangible assets as at December 31, 2021 was work-in-progress in the amount of $1.3 million (2020 - $11.7 million) that was not amortized.

The Company recognized $3.9 million of aggregate amortization expense related to intangible assets during 2021 (2020 - $3.0 million).

The Company capitalized AFUDC of $0.4 million during 2021 (2020 - $0.5 million) to intangible assets. The offset to capitalized AFUDC was recognized as revenue.

The following table sets forth the estimated amortization expense of intangible assets for the years ending December 31:

($ thousands)

2022	$ 4,827
2023	3,769
2024	3,460
2025	3,460
2026	3,460
Thereafter	11,474

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets are recorded based on the expectation that amounts held from one period to the next for rate-setting purposes will be approved for collection from customers in future periods. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through future reductions of, or limitations of increases in, revenue. The recovery or settlement period, or likelihood of recovery or settlement of regulatory assets, is affected by the ultimate treatment determined by the regulator. There is risk and uncertainty that the regulator may not allow full recovery of recorded regulatory assets.

($ thousands)

	Regulatory treatment	**Remaining amortization period**	**2021**	**2020**
Regulatory assets – current:				
Property taxes	Not earning a return	1 year	$ 995	$ 728
Cost of gas	Not earning a return	<1 year	2,496	1,763
Payment deferral	Earning a return	<1 year	169	-
			$ 3,660	$ 2,491

	Regulatory treatment	Remaining amortization period		2021		2020
Regulatory assets – non-current:						
Deferred tax asset	Not earning a return	(1)	$	39,948	$	35,226
Pension losses – transition	Not earning a return	1 year		-		117
Pension losses	Not earning a return	(2)		8,901		24,112
Load balancing	Not earning a return	(4)		62		-
Payment deferral	Earning a return	2 years		-		821
K factor costs	Earning a return	2 years		45		-
Y factor costs	Earning a return	2 years		-		165
			$	48,956	$	60,441

	Regulatory treatment	Remaining amortization period		2021		2020
Regulatory liabilities – non-current:						
Load balancing	Not earning a return	(4)	$	-	$	134
K factor costs	Earning a return	2 years		-		443
Y factor costs	Earning a return	2 years		175		-
Future removal and site restoration costs	Earning a return	(3)		27,898		24,844
			$	28,073	$	25,421

(1) Remaining amortization period varies depending on the timing of underlying transactions.
(2) As the Company has historically recovered and currently recovers its pension costs related to regulated operations in rates, the Company records a regulatory asset for pension funding deficiency. Consequently, the remaining amortization period varies depending on the timing of the underlying transactions.
(3) This amount is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.
(4) Amortization period is dependent on when specified balance thresholds are exceeded in order to trigger a rate rider to collect or refund the load balancing deferral account (LBDA) balance to customers.

Natural gas and transportation costs are included in the approved tariff on a monthly forecast basis. For rate-setting purposes, differences between forecast and actual costs in the month are held for collection or refund in the following months. AUI recognizes the cost variances as a regulatory asset or liability, based on the expectation that amounts held from one month to the next for regulatory purposes will be approved for collection from, or refund to, customers in future months. The Company expects to collect the outstanding deferred balance in the first quarter of the following year. In the absence of rate regulation, US GAAP would require that actual costs be recognized as an expense when incurred.

Property taxes are included in allowed rates on an annual forecast basis. For regulatory purposes, differences between forecast and actual costs in the year are held for collection or refund in the following year. AUI recognizes the cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for regulatory purposes will be approved for collection from, or refund to, customers in future periods. The Company expects to collect from customers the year-end 2021 outstanding deferred cost in 2022 (2020 - collect in 2021). In the absence of rate regulation, US GAAP would require that actual costs be recognized as an expense when incurred.

Deferred income taxes expected to be included in future recoveries from customers are deferred in accordance with ASC 980. In the absence of rate regulation, US GAAP would require that deferred income taxes be recognized in income when incurred.

In the 2010-12 General Rate Application, AUI was approved to establish a mechanism to recover the cumulative pension adjustment related to AUI pension plans for all unrecognized Canadian generally accepted accounting principles (Canadian GAAP) transitional obligations, past service costs and unamortized actuarial gains and losses as of January 1, 2007 and the cumulative differences between pension expenses (excluding other post-employment benefits (OPEB)) recognized under Canadian GAAP versus US GAAP from 2007 to 2011 that would otherwise be charged to equity upon the transition to US GAAP. Transitional deferred pension losses were approved to be collected on a straight-line basis over a 10-year period commencing in 2012. In the absence of rate regulation, US GAAP would require that transitional amounts be charged to equity upon transition to US GAAP.

For regulatory purposes, pension costs (excluding OPEB) are recoverable from customers on an accrual basis, which is equal to pension expense calculated in accordance with ASC 715, *Compensation – Retirement Benefits*, of US GAAP. AUI recognizes a separate pension losses regulatory asset for actuarial gains and losses that would otherwise be recorded to other comprehensive income (loss) if AUI was not rate-regulated. AUI recognizes deferred pension losses related to actuarial gains and losses as a regulatory asset or liability, based on the expectation that amounts held for regulatory purposes will be approved for collection from, or refund to, customers in future periods. In the absence of rate regulation, US GAAP would require that actuarial gains and losses be charged to other comprehensive income (loss) in the period in which they are incurred.

LBDA tracks costs and recoveries related to load balancing by capturing the financial impact of the effects of retailers' account imbalances for deliveries and receipts on AUI's distribution system and accounting for system balancing of transmission capacity AUI contracts for and holds on the TC Energy Pipeline system on behalf of all AUI's gas distribution service customers. AUI recognizes load balancing costs and recoveries as a regulatory asset or liability, based on the expectation that amounts held for regulatory purposes will be approved for collection from, or refund to, customers in future periods. The regulator approved specific LBDA balance thresholds to be exceeded in order to trigger a rate rider to collect or refund the LBDA balance to customers. In the absence of rate regulation, US GAAP would require that costs and recoveries associated with load balancing be recognized in income when incurred.

Future removal and site restoration costs are included in revenue as allowed by the regulator. AUI recognizes the variance between amounts collected and future removal and site restoration costs incurred as a regulatory asset or liability, based on the expectation that amounts held for regulatory purposes will be approved for collection from, or refund to, customers in future periods. In the absence of rate regulation, US GAAP would require that the variance between the amounts collected and incurred be recognized as revenue in the period of collection.

The regulator has approved the direct flow-through recovery or refund of certain costs to customers through K factors and Y factors. K factor and Y factor costs are initially forecast in annual PBR rate applications and approved for collection on an interim basis. In subsequent PBR rate applications, a true-up is calculated as the difference between actual and forecasted costs and is flowed through to customers through an adjustment to rates. Differences between actual and forecasted costs are held as a regulatory asset or liability until collected or refunded to customers through rates. In the absence of rate regulation, US GAAP would require that actual regulatory costs be recognized as an expense when incurred.

The payment deferral asset relates to amounts that have yet to be collected from customers who qualified for the Utility Payment Deferral Program, which was announced by the Government of Alberta in response to the COVID-19 pandemic. Customers were allowed to defer payment of utility bills between March 18 and June 18, 2020 and had the ability to repay the deferred balance in equal monthly installment payments between June 19, 2020 and June 18, 2021. After the program concluded, AUI submitted an application to the AUC for a Utility Payment Deferral Program rate rider on uncollected amounts. On August 18, 2021, the AUC approved AUI's applied for Utility Payment Deferral Program balances to be included within a natural gas rate rider to be collected from all Alberta natural gas customers commencing November 1, 2021. As at December 31, 2021, approximately $0.2 million of the deferral balance remains to be collected from customers in 2022.

10. DEBT

Advances from Parent

As at December 31, 2021, the Company had current advances from the parent corporation of $6.7 million (2020 - $9.8 million). These advances are non-interest bearing with no set terms of repayment.

Short-term Debt

The Company's short-term debt consists of outstanding cheques.

Long-term Debt Payable to Parent

The Company funds its long-term borrowing requirements with borrowings from TUHI.

($ thousands)

Facility	Maturity	Annual interest rate	2021	2020
$40 million debenture, unsecured	March 2024	4.48%	40,000	40,000
$15 million debenture, unsecured	January 2025	3.91%	15,000	15,000
$45 million debenture, unsecured	April 2026	4.20%	45,000	45,000
$10 million debenture, unsecured	April 2026	3.76%	10,000	10,000
$15 million debenture, unsecured	December 2028	4.34%	15,000	15,000
$23 million debenture, unsecured	December 2028	3.12%	23,000	23,000
$20 million debenture, unsecured	January 2044	5.21%	20,000	20,000
$20 million debenture, unsecured	August 2044	4.88%	20,000	20,000
$30 million debenture, unsecured	October 2047	5.03%	30,000	30,000
$30 million debenture, unsecured	April 2027	3.25%	30,000	30,000
$15 million debenture, unsecured	December 2051	3.86%	15,000	-
			$ 263,000	$ 248,000

On June 1, 2012, the Company issued a $20 million unsecured debenture to TUHI with an effective interest rate of 4.14% per annum that matured on June 1, 2020. Interest on the debenture was payable semi-annually in June and December.

On April 29, 2014, the Company issued a $20 million unsecured debenture to TUHI with an effective interest rate of 5.21% per annum that matures on January 13, 2044. Interest on the debenture is payable semi-annually in January and July.

On April 29, 2014, the Company issued a $40 million unsecured debenture to TUHI with an effective interest rate of 4.48% per annum that matures on March 15, 2024. Interest on the debenture is payable semi-annually in March and September.

On August 31, 2015, the Company issued a $15 million unsecured debenture to TUHI with an effective interest rate of 3.91% per annum that matures on January 15, 2025. Interest on the debenture is payable semi-annually in January and July.

On June 29, 2016, the Company issued a $45 million unsecured debenture to TUHI with an effective interest rate of 4.20% per annum that matures on April 7, 2026. Interest on the debenture is payable semi-annually in April and October.

On March 27, 2017, the Company issued a $10 million unsecured debenture to TUHI with an effective interest rate of 3.76% per annum that matures on April 7, 2026. Interest on the debenture is payable semi-annually in April and October.

On March 27, 2017, the Company issued a $20 million unsecured debenture to TUHI with an effective interest rate of 4.88% per annum that matures on August 15, 2044. Interest on the debenture is payable semi-annually in February and August.

On October 30, 2017, the Company issued a $30 million unsecured debenture to TUHI with an effective interest rate of 5.03% per annum that matures on October 4, 2047. Interest on the debenture is payable semi-annually in April and October.

On December 14, 2018, the Company issued a $15 million unsecured debenture to TUHI with an effective interest rate of 4.34% per annum that matures on December 5, 2028. Interest on the debenture is payable semi-annually in June and December.

On December 13, 2019, the Company issued a $23 million unsecured debenture to TUHI with an effective interest rate of 3.12% per annum that matures on December 5, 2028. Interest on the debenture is payable semi-annually in June and December.

On June 1, 2020, the Company issued a $30 million unsecured debenture to TUHI with an effective interest rate of 3.25% per annum that matures on April 7, 2027. Interest on the debenture is payable semi-annually in April and October.

On December 10, 2021, the Company issued a $15 million unsecured debenture to TUHI with an effective interest rate of 3.86% per annum that matures on December 10, 2051. Interest on the debenture is payable semi-annually in June and December.

11. SHARE CAPITAL

Authorized

- Unlimited Class "A" common shares without nominal or par value; and
- Unlimited non-cumulative, redeemable and retractable Class "B" preferred shares without nominal or par value

Issued and Outstanding

($ thousands)

	Number		Amount
Common shares outstanding as at December 31, 2019	2,853,492	$	57,122
Common shares issued during 2020	-		-
Common shares outstanding as at December 31, 2020	2,853,492		57,122
Common shares issued during 2021	-		-
Common shares outstanding as at December 31, 2021	2,853,492	$	57,122

12. INCOME TAXES

The income tax expense recorded in the financial statements differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before income taxes as follows:

($ thousands)

		2021		2020
Income before income taxes	$	16,018	$	15,357
Combined statutory income tax rates		23.00%		24.00%
Expected income tax at combined statutory tax rates		3,684		3,686
Increase (decrease) in income taxes resulting from:				
Amortization less than capital cost allowance claimed for income tax purposes		(2,894)		(1,782)
Costs capitalized for book and expensed for tax purposes		(1,184)		(1,169)
Interest capitalized for book and expensed for tax purposes		(181)		(207)
Amortization of deferred costs in excess of costs incurred		668		815
Employee benefit plan funding deductible for tax purposes, less pension expense		(17)		(227)
Adjustment of prior year filing		(59)		15
Other		22		78
Income tax expense	$	39	$	1,209
Effective income tax rate		0.24%		7.87%

Deferred income tax liability comprises the following:

($ thousands)

		2021		2020
Deferred income tax liability – non-current:				
Property, plant and equipment and intangible assets	$	(37,023)	$	(32,764)
Pension and other benefit plans		3,736		7,346
Regulatory assets and liabilities		(5,606)		(8,370)
Accounts payable and accrued liabilities		4		36
	$	(38,889)	$	(33,752)

Effective July 1, 2020, the Alberta corporate tax rate decreased from 10 percent to 8 percent. As a result of the revaluation of the deferred income tax liabilities using the decreased tax rate, the Company recognized a recovery of $0.03 million of deferred income tax expense for the year ended December 31, 2020.

Canada Revenue Agency (CRA) and Alberta Finance have completed their initial examinations of all tax years through December 31, 2020, and all initial and amended returns have been assessed. As at December 31, 2021, the Company's tax years still open to examination by taxation authorities include 2017 and subsequent years. The Company does not believe that any open tax years for federal or provincial income taxes could result in any adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2021 or 2020. Non-deductible interest incurred in 2021 was $0.02 million (2020 - $0.01 million). The Company recognizes interest accrued related to income tax positions and any penalties incurred as interest expense.

13. STATEMENT OF CASH FLOWS

The net change in non-cash working capital balances related to operations is as follows:

($ thousands)

	2021	2020
Accounts receivable	$ (9,869)	$ 617
Inventory, prepaid expenses and deposits	183	663
Accounts payable and accrued liabilities	6,688	3,701
Income taxes payable (recoverable)	1,398	(1,818)
Right-of-use asset	423	446
Customer deposits	2,490	(33)
Lease liabilities	(423)	(446)
	890	3,130
Change related to contributions in aid of construction	(833)	1,279
Change related to property, plant and equipment and intangible assets	44	1,420
	$ 101	$ 5,829

Cash invested in property, plant and equipment was as follows:

($ thousands)

	2021	2020
Additions to property, plant and equipment	$ (36,538)	$ (37,348)
Items not involving cash:		
Allowance for funds used during construction	350	315
Change in non-cash working capital	(371)	(1,893)
Capitalized amortization	349	327
	$ (36,210)	$ (38,599)

Cash received as contributions in aid of construction was as follows:

($ thousands)

	2021	2020
Contributions in aid of construction	$ 1,447	$ 1,992
Item not involving cash:		
Change in non-cash working capital	833	(1,279)
	$ 2,280	$ 713

Cash invested in intangible assets was as follows:

($ thousands)

	2021	2020
Additions to intangible assets	$ (10,334)	$ (10,921)
Items not involving cash:		
Allowance for funds used during construction	441	548
Change in non-cash working capital	327	473
	$ (9,566)	$ (9,900)

The following cash payments were made during the year:

($ thousands)

	2021	2020
Interest paid	$ 10,559	$ 10,344
Income taxes paid	(1,530)	3,207

14. PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

Substantially all full-time employees of the Company are members of defined benefit non-contributory pension plans. The defined benefit pension plans are funded by contributions by the Company. Pension benefits are based on the employee's length of service and final average earnings. Cash payments of $5.2 million were made by the Company to fund the pension plans during the year (2020 - $5.1 million). These plan contributions were made in accordance with the *Report on the Actuarial Valuation for Funding Purposes as at December 31, 2019* dated September 29, 2020 for each plan. The next actuarial valuation for funding purposes for both plans as at December 31, 2022 will be filed by September 30, 2023.

The Company estimates it will contribute approximately $5.1 million to fund its pension plans in 2022.

The Company also has other benefit plans that provide other post-retirement benefits such as life insurance and health care to certain of its employees. These other benefit plans are not funded.

The net pension and other post-retirement benefit expense recorded for the years 2021 and 2020 was as follows:

($ thousands)

Defined benefit pension plans		**2021**		**2020**
Current service cost	$	5,527	$	4,572
Interest cost		2,060		2,242
Expected return on plan assets		(3,474)		(3,381)
Amortization of prior service cost		5		12
Amortization of net actuarial loss		948		673
Amortization of deferred pension losses		117		117
Net periodic benefit cost	$	5,183	$	4,235

Other post-retirement benefit plans		**2021**		**2020**
Current service cost	$	575	$	369
Interest cost		203		178
Amortization of net actuarial loss		146		31
Net periodic benefit cost	$	924	$	578

The following table summarizes the details of the benefit plans:

($ thousands)

		2021 Defined benefit pension plans		**2021 Other post-retirement benefit plans**		**2020 Defined benefit pension plans**		**2020 Other post-retirement benefit plans**
Change in projected benefit obligation								
Balance, beginning of year	$	87,679	$	8,449	$	75,234	$	5,943
Actuarial loss (gain)		(9,610)		(915)		8,499		2,090
Current service cost		5,527		575		4,572		369
Interest cost		2,060		203		2,242		178
Expenses paid		(181)		-		(179)		-
Benefits paid		(2,918)		(157)		(2,689)		(131)
Balance, end of year		82,557		8,155		87,679		8,449
Fair value of plan assets								
Balance, beginning of year		64,190		-		56,031		-
Actual return on plan assets		8,122		-		5,847		-
Employer contributions		5,257		157		5,180		131
Benefits paid		(2,918)		(157)		(2,689)		(131)
Expenses paid		(181)		-		(179)		-
Balance, end of year		74,470		-		64,190		-
Net benefit obligation recognized in financial statements	$	(8,087)	$	(8,155)	$	(23,489)	$	(8,449)

At December 31, 2021, for the defined benefit pension plans, the most significant source of actuarial gain is the increase in the applicable bond yields used to determine the present value of obligations.

At December 31, 2021, for the other post-retirement benefit plans, the most significant sources of actuarial gain include the increase in the applicable bond yields used to determine the present value of obligations.

The following amounts were not recognized as a component of net periodic benefit cost:

($ thousands)

	2021 Defined benefit pension plans	2021 Other post-retirement benefit plans	2020 Defined benefit pension plans	2020 Other post-retirement benefit plans
Net actuarial loss	$ (8,901)	$ (2,083)	$ (24,112)	$ (3,144)
Less regulatory asset	(8,901)	-	24,112	-
Total accumulated other comprehensive loss on pre-tax basis	-	(2,083)	-	(3,144)
Increase by the amount included in deferred tax liabilities	-	488	-	732
Net amount in accumulated other comprehensive loss, net of tax	$ -	$ (1,595)	$ -	$ (2,412)

The Company has three defined benefit pension plans. The following table summarizes the details of the three plans:

($ thousands)

	Salaried employees' pension plan		Bargaining unit pension plan		SERP	
	2021	2020	2021	2020	2021	2020
Fair value of plan assets	45,979	40,088	28,487	24,099	-	-
Projected benefit obligation	50,312	53,447	31,693	33,623	552	609
Deficit	(4,333)	(13,359)	(3,206)	(9,524)	(552)	(609)
Accumulated benefit obligation	41,753	44,690	25,784	27,076	552	609

The pension plan assets are invested under balanced fund mandates with a broad mix of fixed income, Canadian equity, and foreign equity investments. The collective investment mixes for the plans are as follows:

December 31	2021	2020
Canadian equity securities	24%	30%
Foreign equity securities	31%	20%
Fixed income	39%	44%
Real estate	6%	6%
	100%	100%

The table below provides the fair values of AUI's pension plan assets as at December 31, 2021. The table also identifies the level of inputs used in the fair value hierarchy to determine the fair value of assets in each category.

($ thousands)

December 31, 2021	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 449	$ -	$ -	$ 449
Canadian equity securities	17,762	-	-	17,762
Foreign equity securities	22,994	-	-	22,994
Fixed income	28,858	-	-	28,858
Real estate	-	4,403	-	4,403
Total	$ 70,063	$ 4,403	$ -	$ 74,466

Significant actuarial assumptions used in measuring net benefit cost as at December 31, 2021	**Salaried employees' pension plan**	**Bargaining unit pension plan**	**SERP**	**Other post-retirement benefit plans**
Discount rate (percent)	2.34 to 2.91	2.44 to 2.92	1.98 to 2.53	2.43 to 2.79
Expected long-term rate of return on plan assets (percent)	5.29	5.29	n/a	n/a
Average remaining service life of active employees (years)	16.77	15.31	18.93	15.70
Rate of compensation increase (percent)				
2021 and thereafter	3.00	3.00	n/a	1.50 to 3.00

Significant actuarial assumptions used in measuring net benefit cost as at December 31, 2020	**Salaried employees' pension plan**	**Bargaining unit pension plan**	**SERP**	**Other post-retirement benefit plans**
Discount rate (percent)	3.00 to 3.21	3.05 to 3.21	2.84 to 3.09	3.03 to 3.17
Expected long-term rate of return on plan assets (percent)	5.92	5.92	n/a	n/a
Average remaining service life of active employees (years)	16.77	15.31	19.72	15.70
Rate of compensation increase (percent)				
2020	2.00	1.50	n/a	3.00
2021 and thereafter	3.00	3.00	n/a	3.00

Significant actuarial assumptions used in measuring benefit obligations as at December 31, 2021	**Salaried employees' pension plan**	**Bargaining unit pension plan**	**SERP**	**Other post-retirement benefit plans**
Discount rate (percent)	3.32	3.34	3.11	3.33
Rate of compensation increase (percent)				
2021	3.00	1.50	n/a	1.50 to 3.00
2022 and thereafter	3.00	3.00	n/a	3.00

Significant actuarial assumptions used in measuring benefit obligations as at December 31, 2020	**Salaried employees' pension plan**	**Bargaining unit pension plan**	**SERP**	**Other post-retirement benefit plans**
Discount rate (percent)	2.77	2.81	2.53	2.79
Rate of compensation increase (percent)				
2020	2.00	1.50	n/a	1.50 to 2.00
2021 and thereafter	3.00	3.00	n/a	3.00

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 6.00 percent and the ultimate trend rate is 4.00 percent, which is assumed to be achieved by 2040.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

($ thousands)

	Defined benefit pension plans	**Other post-retirement benefit plans**
2022	$ 2,115	$ 166
2023	2,205	170
2024	2,324	179
2025	2,460	196
2026	2,609	215
2027–2031	15,317	1,396

15. RELATED PARTY TRANSACTIONS

In the normal course of business, the Company has transactions with related parties. AltaGas Ltd. (ALA) ceased to be associated with the Company on closing of the Arrangement on March 31, 2020.

The following related party transactions are measured at their exchange amounts:

($ thousands)

		2021		2020
Fees for administration, management and other services charged to the Company by TSU (and companies related to TSU) and ALA (and companies related to ALA)	$	3,865	$	4,136
Fees for administration, management and other services provided by the Company to ALA (and companies related to ALA) and TSU (and companies related to TSU)		2,772		2,371
Interest expense charged by TUHI on debentures and advances		10,550		10,457
Gas purchases for resale from a company related to ALA		-		7,238
Unrealized loss (gain) on foreign exchange contracts with TSU		(226)		226

The resulting amounts due from and to related parties are non-interest bearing and relate to transactions in the normal course of business.

Included in accounts receivable as at December 31, 2021 is $0.7 million (2020 - $0.1 million) due from TSU (and companies related to TSU).

Included in accounts payable and accrued liabilities as at December 31, 2021 is $3.7 million (2020 - $4.5 million) due to TSU (and companies related to TSU). Also, due to TSU is foreign exchange contract liabilities of $nil (2020 – $0.2 million).

Of the fees charged to the Company, $2.9 million (2020 - $3.1 million) is included in operating and administrative expenses, $0.8 million (2020 - $0.8 million) is included in intangible assets and $0.2 million (2020 - $0.2 million) is included in prepaid expenses and deposits. Of the fees charged by the Company, $1.3 million (2020 - $1.5 million) is charged as a recovery against operating and administrative expenses, $1.3 million (2020 - $0.7 million) is included in revenue, $0.2 million (2020 - $0.04 million) is included in intangible assets and $nil (2020 - $0.07 million) is recorded as an offset to prepaid expenses and deposits. Interest charged to the Company of $10.5 million (2020 - $10.5 million) is included in interest expense on long-term debt payable to parent. Of the gas purchases, $nil related party amounts are recorded in either cost of natural gas (2020 - $5.8 million) or deferred cost of gas (2020 - $1.4 million).

16. CONTINGENCIES

In the normal course of operations, the Company is subject to various claims and, at times, legal actions. Based on advice and information provided by legal counsel, management believes that the resolution of such matters will not have a material adverse effect on the Company's financial position or results of operations.

17. COMMITMENTS

The Company has long-term natural gas demand delivery contracts, which are transacted at market prices and in the normal course of business. These contracts, which have expiration dates that range from 2022 to 2027, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and minimize exposure to supply restrictions.

The Company also has a long-term contract for software implementation, hosting and support that expires in 2031 and an equipment rental agreement that expires in 2025.

Future payments of these commitments as at December 31, 2021 are estimated as follows:

($ thousands)

2022	$	11,136
2023		10,976
2024		10,949
2025		9,807
2026		7,249
Thereafter		11,328

18. SUBSEQUENT EVENTS

Under current accounting guidance, the Company is required to disclose events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. These are known as “subsequent events.” Subsequent events have been reviewed through March 9, 2022, the issuance date of these financial statements. There are no subsequent events requiring an adjustment to or disclosure in the financial statements.

ATCO Electric Distribution
2021 Alberta Utilities Commission Rule 005 Filing
April 29, 2022

April 29, 2022

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta   T2P 0G5

Attention: **Kristjana Kellgren**
Executive Director, Rates Division

Re: **ATCO Electric Distribution**
AUC Rule 005
Annual Reporting of Financial and Operational Results

In accordance with the Alberta Utilities Commission (AUC or the Commission) Rule 005, please find enclosed ATCO Electric Distribution's (AED) 2021 Annual Reporting of Financial and Operational Results.

Should you have any questions regarding this submission, please do not hesitate to contact the undersigned at (587) 983-4054 or jennifer.bagnall@atco.com if you have any questions or require further information.

Yours truly,

Jennifer Bagnall, CPA, CMA
Director, Regulatory

ATCO Electric
SUMMARY OF REVENUE REQUIREMENT (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	
1	Return	Sch 2.0-D	197.2	166.3	30.9	18.6%	
2	Transmission Access Payments		429.1	481.7	(52.6)	-10.9%	**Note 1**
3	Fuel and Non-Pool Energy		7.5	9.6	(2.1)	-22.0%	**Note 2**
4	Operating and Maintenance	Sch 3.0-D	184.8	185.6	(0.7)	-0.4%	
5	Depreciation and Amortization	Sch 4.0-D	131.3	128.7	2.6	2.1%	
6	Utility Income Tax	Sch 5.0-D	(12.1)	(14.1)	2.0	-14.0%	
7	Subtotal		937.8	957.7	(20.0)	-2.1%	
8	Revenue Offsets	Sch 6.0-D	(18.6)	(13.3)	(5.2)	39.3%	**Note 3**
9	**Total Distribution Revenue Requirement**	Sch 10	919.2	944.4	(25.2)	-2.7%	
10	Detailed Revenue						
11	Distribution Tariff Revenue	Sch 6.0-D	875.7	878.8	(3.2)	-0.4%	
12	Deferral Accounts		43.5	65.5	(22.0)	-33.6%	**Note 4**
13	**Total Detailed Revenue**	Sch 10	919.2	944.4	(25.2)	-2.7%	
14	**Deferral Account**						
15	TAP Deferral		(4.3)	70.0	(74.3)	-106.2%	
16	AESO Load Settlement		0.0	0.0	0.0	52.1%	
17	Deducting Deferral for Income Tax		(14.6)	(4.4)	(10.2)	233.9%	
18	Rate Case Collections		(0.4)	(0.1)	(0.3)	234.7%	
19	Rate Relief Deferral		62.8	-	62.8	0.0%	
20	**Total Deferral Account**		43.5	65.5	(22.0)	-33.6%	**Note 4**

Note 1 Transmission Access Payments were lower in 2021 mainly due to lower Deferral Account Reconcilation (DAR) from the AESO.

Note 2 Fuel and Non-Pool Energy costs were lower in 2021 mainly due to higher offsetting revenue related to an increase is usage of distribution interchange.

Note 3 Refer to Schedule 6, Note 3.

Note 4 2021 Actual is lower mainly due to a lower net collection position of the TAP Deferral as a result of lower DAR costs, partially offset by the Rate Relief Deferral.

ATCO Electric
SUMMARY OF RETURN ON RATE BASE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

2021 Actual

Line No.	Description	Cross-Reference	Mid-Year Capital	Deemed Structure	Prorated Rate Base	Cost Rate (%)	Return ($)
1	Long-Term Debt	Sch 2.3-D	1,740.1	61.44%	1,596.7	4.52%	72.1
2	Preferred Shares	Sch 2.4-D	44.1	1.56%	40.5	3.85%	1.6
3	Common Equity	Sch 2.2-D	1,047.9	37.00%	961.5	12.85%	123.5
4	**Mid-Year Net Rate Base**	Sch 1.0-D	2,832.2	100.00%	2,598.6	7.59%	197.2
5	Contribution for Extensions				800.5		
6	No Cost Capital	Sch 2.1-D			-		
7	**Mid-Year Rate Base**				3,399.1		
8	Return on Common Equity	Line 3				12.85%	123.5

ATCO Electric
SUMMARY OF MID-YEAR RATE BASE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)
1	**Gross Utility Plant in Service**					
2	Opening Balance	Sch 4.1-D	5,017.8	4,833.8	184.0	3.8%
3	Closing Balance	Sch 4.1-D	5,163.2	5,017.8	145.4	2.9%
4	**Mid-Year Gross Utility Plant in Service**		5,090.5	4,925.8	164.7	3.3%
5	**Accumulated Depreciation - Distribution**					
6	Opening Balance	Sch 4.1-D	1,620.1	1,525.3	94.8	6.2%
7	Closing Balance	Sch 4.1-D	1,720.9	1,620.1	100.8	6.2%
8	**Mid-Year Accumulated Depreciation - Distribution**		1,670.5	1,572.7	97.8	6.2%
9	**Contributions in Aid of Construction**					
10	Opening Balance		1,165.0	1,120.3	44.7	4.0%
11	Closing Balance		1,188.4	1,165.0	23.4	2.0%
12	**Mid-Year Utility Contributions in Aid of Construction**		1,176.7	1,142.7	34.1	3.0%
13	**Amortization of Contributions**					
14	Opening Balance		364.6	344.4	20.2	5.9%
15	Closing Balance		387.9	364.6	23.3	6.4%
16	**Mid-Year Utility Amortization of Contributions**		376.2	354.5	21.7	6.1%
17	**Mid-Year Net Utility Plant in Service**		2,619.5	2,564.9	54.6	2.1%
18	Necessary Working Capital		11.2	9.3	1.9	20.6%
19	Farms, Irrigation Transmission		(32.0)	(31.3)	(0.7)	2.3%
20	No Cost Capital		-	-	-	0.0%
21	**Mid-Year Net Rate Base**	Sch 2.0-D	2,598.6	2,542.9	55.7	2.2%

ATCO Electric

SUMMARY OF MID-YEAR CAPITAL STRUCTURE (DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

($MILLIONS)

Line No.	Description	Cross-Reference	Current Year-End	Previous Year-End	Actual 2021 Mid-Year Capital
1	Long-Term Debt	Sch 2.3	1,743.9	1,736.4	1,740.1
2	Preferred Shares	Sch 2.4	36.2	52.0	44.1
3	Common Equity		1,072.7	1,023.1	1,047.9
4	**Total Mid-Year Invested Capital**		2,852.8	2,811.6	2,832.2

ATCO Electric
SUMMARY OF DEBT CAPITAL EMPLOYED (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

2021 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate (%)	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. Parent											
2			Z	1991-12-18	2022	9.920%	20.7	0.3	20.4	9.978%	20.7	2.1	
3			AA	1992-12-08	2023	9.400%	9.7	0.1	9.6	9.453%	9.7	0.9	
4			2004	2004-11-18	2034	5.896%	50.0	0.3	49.7	5.940%	49.9	3.0	
5			2005	2005-11-30	2035	5.183%	39.7	0.3	39.4	5.227%	39.5	2.1	
6			2006	2006-11-20	2036	5.032%	41.7	0.3	41.5	5.074%	41.6	2.1	
7			2007	2007-11-01	2037	5.556%	55.8	0.3	55.4	5.602%	55.5	3.1	
8			2008	2008-05-26	2028	5.563%	20.7	0.1	20.5	5.615%	20.6	1.2	
9			2008	2008-05-26	2038	5.580%	31.0	0.2	30.8	5.630%	30.8	1.7	
10			2009	2009-03-06	2024	6.215%	47.9	0.3	47.6	6.270%	47.9	3.0	
11			2009	2009-03-07	2039	6.500%	60.3	0.4	59.9	6.560%	60.0	3.9	
12			2010	2010-11-01	2050	4.947%	51.7	0.4	51.3	4.998%	51.3	2.6	
13			2011	2011-10-24	2041	4.543%	135.8	0.8	135.0	4.582%	135.1	6.2	
14			2011	2011-10-24	2061	4.593%	54.3	0.3	54.0	4.625%	54.0	2.5	
15			2012	2012-09-10	2042	3.805%	60.7	0.4	60.3	3.840%	60.4	2.3	
16			2012	2012-09-10	2062	3.825%	24.2	0.1	24.1	3.853%	24.1	0.9	
17			2012	2012-11-14	2052	3.857%	30.8	0.2	30.6	3.888%	30.7	1.2	
18			2013	2013-09-04	2043	4.722%	229.0	1.5	227.5	4.763%	227.7	10.8	
19			2014	2014-09-08	2044	4.085%	250.0	1.5	248.5	4.122%	248.7	10.3	
20			2015	2015-07-27	2045	3.964%	100.0	0.6	99.4	4.002%	99.4	4.0	
21			2016	2016-11-17	2046	3.763%	125.0	0.8	124.2	3.799%	124.2	4.7	
22			2017	2017-11-22	2047	3.548%	130.0	0.9	129.1	3.583%	129.2	4.6	
23			2018	2018-11-21	2048	3.950%	45.0	0.3	44.7	3.988%	44.7	1.8	
24			2019	2019-09-05	2049	2.963%	60.0	0.4	59.6	2.996%	59.6	1.8	
25			2020	2020-09-28	2050	2.609%	25.0	0.2	24.8	2.644%	24.8	0.7	
26			2021	2021-09-03	2051	3.174%	160.0	1.1	158.9	3.209%	158.9	5.1	
27											**1,849.1**	**82.5**	**4.46%**
28		Short-Term Debt (Investment)											
29		Notes Payable - REA				3.200%	6.9				6.87	0.2	
30		Less: 2021 Subsidiary Debt Financing					112.1				112.1	5.0	4.46%
31		Current Year End Balance					1,753.9				1,743.9	77.7	4.46%
32		Prior Year End Balance											4.58%
33											3,480.3	157.3	
34	**Sch 2.2**	**Mid-year Balance**									**1,740.1**	**78.6**	**4.52%**

Note: In accordance with Commission Direction 4 in Decision 22570-D01-2018, the 2021 actual debt rate cost is 4.56%.

ATCO Electric

SUMMARY OF PREFERRED SHARE CAPITAL EMPLOYED (DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

($MILLIONS)

2021 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1		1	2007	4.60%	22.1	-	22.1	1.0	4.60%
2		4	2010	2.29%	14.1	-	14.1	0.3	2.29%
3		Current Year End Balance			36.2	-	36.2	1.3	3.70%
4		Prior Year End Balance				-			3.96%
5		Total			88.2		88.2	3.4	3.85%
6	**Sch 2.2-D**	**Mid-year Balance**			**44.1**		**44.1**	**1.7**	**3.85%**

Note: Series V preferred shares were redeemed in 2021.
Series 4 preferred shares reset in 2021.

ATCO Electric
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.		Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	Variance Explanation
1		**Account Services & Public Information**						
2	908	Customer Assistance Expenses		1.2	1.2	(0.1)	-5.3%	
3	909	Informational and Instructional Advertising Expense		0.3	0.2	0.1	60.3%	
4	910	Miscellaneous Customer Service and Informational Expense		0.5	0.5	(0.0)	-3.4%	
5		IT G&A Expense		-	-	-	0.0%	
6				2.0	2.0	0.0	1.9%	
7		**Customer Accounting**						
8	901	Supervision		0.0	0.0	(0.0)	-98.8%	
9	902	Meter Reading Expense		1.8	1.9	(0.1)	-5.4%	
10	903	Customer Records and Collection Expenses		2.9	2.1	0.7	35.3%	
11	904	Uncollectible Accounts		0.3	0.6	(0.3)	-57.4%	
12	905	Miscellaneous Customer Accounts Expenses		-	-	-	0.0%	
13	905.1	IT Customer Service		1.5	2.1	(0.6)	-28.5%	**Note 1**
14				6.4	6.7	(0.3)	-4.7%	
15		**Direct Operation & Maintenance Expense**						
16	580	Supervision and Engineering		2.4	2.6	(0.2)	-6.2%	
17	581	Control Center Operations		1.6	1.6	0.0	2.4%	
18	583	Overhead Line Expenses		12.9	12.1	0.8	6.6%	
19	584	Underground Line Expenses		2.4	2.3	0.1	4.4%	
20	585	Street Lighting and Signal System Expenses		1.1	1.2	(0.1)	-8.5%	
21	586	Meter Expenses		1.5	1.1	0.4	34.0%	
22	588	Miscellaneous Distribution Expenses		27.7	24.4	3.3	13.4%	**Note 2**
23	593.1	Vegetation Management		14.2	11.4	2.8	24.7%	**Note 3**
24	595	Line Transformers		0.0	0.0	(0.0)	-46.1%	
25	944	Load Settlement		0.5	0.2	0.2	92.3%	
26	944.1	IT Load Settlement		-	1.7	(1.7)	-100.0%	**Note 1**
27	599	Support		-	5.1	(5.1)	-100.0%	**Note 1**
28				64.3	63.8	0.5	0.8%	
29		Isolated Generation Operation & Maintenance		0.0	0.038	(0.0)	-22.0%	
30		Allocated Share of General Operation & Maintenance		7.1	8.0	(0.9)	-10.7%	
31		Allocated Share of Common Operations		-	-	-	0.0%	
32				7.1	8.0	(0.9)	-10.8%	
33		**Corporate Operation & Maintenance Expense**						
34	920	General Administration		18.2	17.0	1.2	7.4%	**Note 4**
35	921	Office Supplies and Expenses		5.6	7.9	(2.3)	-29.4%	**Note 5**
36	923	Outside Services Employed		0.3	0.3	(0.0)	-5.8%	
37	924	Insurance Premiums		1.9	1.7	0.2	13.9%	
38	925	Injuries and Damages		0.6	1.2	(0.6)	-48.2%	
39	928	Board Expenses		0.9	1.1	(0.3)	-22.9%	
40	930.2	Miscellaneous General Expenses		20.2	20.2	(0.1)	-0.4%	
41	931.1	Head Office Rent		1.7	1.9	(0.1)	-7.9%	
42	934	IT G&A Expense		26.8	25.6	1.3	4.9%	**Note 1**
43	941	Board Expenses Disallowed		-	-	-	0.0%	
44				76.2	76.9	(0.7)	-0.9%	
45		Non-Utility Items		(5.0)	(3.9)	(1.1)	28.0%	**Note 6**
46		**Total Administration and General**		71.2	73.0	(1.8)	-2.4%	
47		Taxes Other Than Income		34.5	32.8	1.6	5.0%	
48		Farms, Irrigation Transmission Operating Costs		(0.6)	(0.7)	0.1	-7.8%	
49		**Total Distribution Operating & Maintenance Costs**		184.8	185.6	(0.7)	-0.4%	

Note 1 As certain IT costs have been reclassified in 2021, an explanation of total IT operating costs comprised of the variances for USA accounts 905.1, 944.1, 599, and 934 is being provided. Total IT costs are lower than 2020 mainly due to lower IT transition costs associated with the re-alignment of IT services.

Note 2 Miscellaneous Distribution Expenses are higher than 2020 mainly due to higher costs for affiliate cost of goods sold, severance, and labour.

Note 3 Vegetation Management is higher than 2020 mainly due to an increase in costs as a result of additional mechanical treatments.

Note 4 General Administration is higher than 2020 mainly due to higher bonuses and MTIP partially offset by lower labour due to vacancies.

Note 5 Office Supplies and Expenses are lower than 2020 mainly due to lower restructuring costs and lower aircraft usage partially offset by higher sponsorship costs.

Note 6 Non-Utility Items are higher than 2020 mainly due to higher license fees and sponsorships.

ATCO Electric
SUMMARY OF DEPRECIATION EXPENSE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	
1	Distribution		130.6	126.1	4.5	3.6%	
2	Amortization of Differences		0.2	0.2	(0.0)	0.0%	
3	**Subtotal**		**130.9**	**126.4**	**4.5**	**3.6%**	
4	**Direct General PP&E**						
5	Structures & Improvements		6.9	6.9	0.0	0.6%	
6	Office Furniture and Equipment		1.1	1.2	(0.0)	-1.4%	
7	Computer Equipment		0.5	0.4	0.1	30.4%	
8	Transportation Equipment		5.7	5.3	0.4	7.5%	
9	Tools & Instruments		2.0	2.1	(0.0)	-1.0%	
10	Communication Equipment		0.9	0.9	(0.0)	-0.1%	
11	Housing		0.0	0.0	0.0	0.2%	
12	Leasehold Improvements		0.2	0.3	(0.1)	-23.4%	
13	Software		12.9	14.6	(1.7)	-11.7%	
14	Amortization of Differences		3.4	3.4	(0.0)	0.0%	
15	**Subtotal**		**33.7**	**35.0**	**(1.2)**	**-3.6%**	
16	**Distribution Gross Provision**		**164.6**	**161.3**	3.3	2.0%	
17	Farms, Irrigation Transmission		(1.4)	(1.5)	0.1	-8.0%	
18	**Total Distribution Gross Depreciation Expense**		**163.2**	**159.8**	**3.4**	**2.1%**	
19	Gross Depreciation Expense		163.2	159.8	3.4	2.1%	
20	Vehicle Depreciation Capitalized		(5.0)	(4.6)	(0.3)	7.4%	
21	Amortization of Contributions		(26.9)	(26.5)	(0.4)	1.4%	
22	**Total Depreciation and Amortization Expense**	Sch 1.0-D	131.3	128.7	2.6	2.1%	**Note 1**

Note 1 Total Depreciation and Amortization expense is higher than prior year mainly due to a higher opening depreciable base as well as an increase in depreciation resulting from 2021 capital additions.

ATCO Electric
CAPITAL ASSETS CONTINUITY SCHEDULE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
1	Distribution		4,448.7	159.2	(20.8)	(0.1)	(0.1)	4,586.9
2	**Direct General PP&E**							
3	Land		18.0	-	-	(0.2)	-	17.8
4	Structures and Improvements		305.2	3.9	(1.3)	-	-	307.8
5	Office Furniture and Equipment		9.9	0.1	(0.2)	-	-	9.7
6	Computer Equipment		1.1	2.2	(0.0)	-	-	3.2
7	Transportation Equipment		93.4	5.3	(5.0)	-	-	93.7
8	Tools and Instruments		19.1	1.5	(1.4)	-	-	19.2
9	Communication Equipment		10.0	0.0	-	-	-	10.0
10	Housing		1.8	0.0	(0.3)	-	-	1.5
11	Leasehold Improvements		0.5	0.2	(0.7)	-	-	(0.0)
12	Other		110.1	15.4	(12.2)	-	-	113.3
13	**Subtotal**		569.1	28.7	(21.2)	(0.2)	-	576.3
14	**Total**	Sch 2.1-D	5,017.8	187.8	(42.1)	(0.2)	(0.1)	5,163.2
15	Capital Work in Progress (CWIP)		79.7	30.8	-	-	-	110.5
16	**Total Distribution**		5,097.5	218.6	(42.1)	(0.2)	(0.1)	5,273.7

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Depreciation Provision	2021 Retirements	2021 Net Salvage	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
17	Distribution		1,444.1	130.9	(20.8)	(21.4)	-	(0.0)	1,532.7
18	**Direct General PP&E**								
19	Structures and Improvements		50.5	7.1	(1.3)	(0.9)	-	-	55.4
20	Office Furniture and Equipment		8.3	1.2	(0.2)	(0.0)	-	-	9.3
21	Computer Equipment		0.1	0.7	(0.0)	-	-	-	0.8
22	Transportation Equipment		33.8	6.8	(5.0)	0.7	-	-	36.3
23	Tools and Instruments		9.0	2.5	(1.4)	-	-	-	10.1
24	Communication Equipment		6.3	1.1	-	-	-	-	7.4
25	Housing		(0.1)	0.1	(0.3)	(0.0)	-	-	(0.3)
26	Leasehold Improvements		1.6	0.9	(0.7)	-	-	-	1.7
27	Other		66.4	13.4	(12.2)	-	-	-	67.6
28	**Subtotal**		175.9	33.7	(21.2)	(0.2)	-	-	188.2
29	**Total Distribution**	Sch 2.1-D	1,620.1	164.6	(42.1)	(21.7)	-	(0.0)	1,720.9

ATCO Electric
SUMMARY OF CAPITAL EXPENDITURES (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	2021 Actual Opening CWIP	2021 Actual Capital Expenditures	2021 Actual Capital Additions	2021 Actual Closing CWIP	2020 Actual Opening CWIP	2020 Actual Capital Expenditures	2020 Actual Capital Additions	2020 Actual Closing CWIP	Variance to Prior Year ($)	Variance (%)
1	**SMALL NEW EXTENSIONS**										
2	Residential / Commercial Extensions	4.7	33.3	31.5	6.5	5.7	33.8	34.8	4.7		
3	Oilfield / Industrial Extensions	16.2	33.1	32.3	17.0	28.1	32.9	44.8	16.2		
4	Street and Sentinel Lights	1.3	4.8	4.6	1.5	3.9	3.5	6.1	1.3		
5		22.2	71.2	68.4	25.0	37.7	70.2	85.7	22.2	(17.3)	-20%
6	**LARGE NEW EXTENSIONS**										
7	Fox Coulee DG	0.1	0.6	-	0.7	-	0.1	-	0.1		
8	Saddle Hills Battery	-	0.1	0.1	-	0.9	1.0	1.9	-		
9	Distribution Generation Projects	0.7	0.7	-	1.4	-	0.7	-	0.7		
10	Earring Lake Oilfield	-	-	-	-	0.2	-	0.2	-		
11	Poplar Hill Sour Gas Plant	0.1	(0.1)	-	(0.0)	2.1	4.4	6.4	0.1		
12	Fox Creek	2.0	3.4	2.1	3.3	3.6	7.7	9.3	2.0		
13	Gold Creek Area New Extension	0.2	(0.2)	-	-	0.1	0.1	-	0.2		
14	Goose River Pad	0.1	(0.1)	-	(0.0)	-	0.1	-	0.1		
15	SAGD Project - Construction Power	-	-	-	-	-	0.2	0.2	-		
16	Lator Pumping Station Expansion	-	-	-	-	-	0.1	0.1	-		
17	Mowatt Mulligan	0.1	-	0.1	-	-	(0.1)	(0.2)	0.1		
18	Oil and Gas	-	-	-	-	-	0.1	0.1	-		
19	Gordondale Gas PlantPhase 8	0.2	-	-	0.2	-	0.2	-	0.2		
20	Hythe Pump Station	-	0.2	0.2	-	-	0.1	0.1	-		
21	Series Pad 40	-	-	-	-	0.9	(0.9)	-	-		
22	Karr Area Development	1.9	3.4	5.3	-	-	1.9	-	1.9		
23	Sunrise DA2 WP 16-16	0.2	-	-	0.2	0.1	0.1	-	0.2		
24	TallCree	-	0.1	0.1	-	0.1	4.0	4.1	-		
25	Kakwa Area Mainline	0.1	-	0.1	(0.0)	1.3	5.8	7.0	0.1		
26	Meander River 3 Phase Conversion	-	4.1	4.1	-	-	-	-	-		
27	Various Other Projects below $0.5 individually	-	-	-	-	-	-	-	-		
28		5.7	12.2	12.1	5.8	9.3	25.6	29.2	5.7	(17.1)	-59%
29	**CAPITAL MAINTENANCE**										
30	Small Projects New Technology	1.0	0.8	1.2	0.6	1.0	1.3	1.3	1.0		
31	Overhead Rebuilds, Replacement and Life Extension	2.0	10.8	9.5	3.3	1.2	11.5	10.7	2.0		
32	Capital Forest Management	0.1	9.4	9.4	0.1	-	5.1	5.0	0.1		
33	Small Projects Capacity Increase	0.8	0.9	1.5	0.2	-	1.2	0.4	0.8		
34	Pole Replacements and Life Extension	2.4	19.3	17.8	3.9	4.6	17.8	20.0	2.4		
35	Conductor and Cable Replacement	0.1	4.9	4.4	0.6	-	4.2	4.1	0.1		
36	Reliability Improvements	1.0	1.4	1.3	1.1	-	2.8	1.8	1.0		
37	Meter Fleet Compliance Program - Electromechanical Meters Ph 2 & 3 (2018, 2019, 2020, 2021)	-	2.7	2.2	0.5	0.3	2.0	2.3	-		
38	Distribution Asset Data Documentation and Validation	-	0.7	0.7	-	-	1.7	1.7	-		
39	Grid Modernization: Distribution SCADA & ADMS	1.6	3.4	3.0	2.0	0.1	2.4	0.9	1.6		
40	Grid Resiliency and Wildfire Mitigation	2.2	7.3	5.1	4.4	-	5.4	3.2	2.2		
41	Meter Fleet Compliance Program - Advanced Metering Infrastructure (AMI – Disconnect/Reconnect)	-	-	-	-	-	0.9	0.9	-		
42	Advanced Metering Infrastructure – RF	0.1	5.8	5.6	0.3	0.2	3.2	3.3	0.1		
43	5L34 Reliability Improvements & Marion Lake Contingency Tie	-	-	-	-	-	0.3	0.3	-		
44	5L215 Jasper Miette Line	1.6	7.1	8.6	0.1	-	1.6	-	1.6		
45	5L451 River Crossing	-	-	-	-	0.8	0.7	1.5	-		
46	Various Other Projects below $0.5 individually	-	-	-	-	-	-	-	-		
47		12.9	74.5	70.3	17.1	8.2	62.1	57.4	12.9	12.9	22%

ATCO Electric

SUMMARY OF CAPITAL EXPENDITURES (DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

($MILLIONS)

		2021 Actual				2020 Actual					
Line No.	Description	Opening CWIP	Capital Expenditures	Capital Additions	Closing CWIP	Opening CWIP	Capital Expenditures	Capital Additions	Closing CWIP	Variance to Prior Year ($)	Variance (%)
48	**LARGE SYSTEM IMPROVEMENTS**										
49	Wild Fire Rights-of-Way	0.7	14.8	14.6	0.9	0.6	14.8	14.7	0.7		
50	Double Circuit Clearance Mitigation	-	-	-	-	0.2	(0.0)	0.2	-		
51	Distribution Automation	-	1.1	0.1	1.0	0.8	0.8	1.6	-		
52	City of Grande Prairie Dist Lines New Hughes Substation	-	-	-	-	0.1	(0.1)	-	-		
53	Transmission Driven Work	-	-	-	-	0.5	0.1	0.6	-		
54	Distribution Line Relocation for Vegreville substation rebuild 50075	-	-	-	-	-	0.1	0.1	-		
55	Narrows Point	-	-	-	-	1.6	2.1	3.7	-		
56	Line Moves and Encroachment	0.1	5.6	4.7	1.0	3.2	2.8	5.9	0.1		
57	6L79 Central East Distribution Interconnections	-	-	-	-	-	(0.1)	(0.1)	-		
58	Salvage of Vacant Dispositions (Land for Existing Assets)	-	-	-	-	-	0.2	0.2	-		
59	La Crete area study(voltage/capacity)	0.1	0.1	0.2	0.0	0.2	5.9	6.0	0.1		
60	Highway 43 Road Crossings	0.2	1.2	1.4	-	0.1	1.1	1.0	0.2		
61	Rainbow Lake Sub Rebuild	-	-	-	-	-	-	-	-		
62	Ft McMurray flooding 2020	-	-	-	-	-	0.5	0.5	-		
63	CNRL Horizon Line Move	-	0.1	-	0.1	-	-	-	-		
64	Various Other Projects below $0.5 individually	-	-	-	-	-	0.1	0.1	-		
65		1.1	22.9	21.0	3.0	7.3	28.3	34.5	1.1	(13.5)	-39%
66	**DISTRIBUTION CONTRIBUTIONS TO TRANSMISSION**										
67	54501 Wapiti 823S Capcity Addition	0.1	-	-	0.1	-	0.1	-	0.1		
68	55633 Surmont II (Stages 3)	-	-	-	-	-	0.2	0.2	-		
69	55680 Hangingstone SAGD	-	-	-	-	-	0.2	0.2	-		
70	AOSPL	0.1	-	-	0.1	-	0.1	-	0.1		
71	Cavendish Substation	0.1	(2.0)	(1.9)	-	1.0	4.5	5.4	0.1		
72	Eyre 588S Substation Interconnection	0.1	-	-	0.1	0.1	-	-	0.1		
73	Germain 144kV Line and Substation	-	-	-	-	-	3.7	3.7	-		
74	Ksituan River Sub 754S Upgrade - AESO Project 1658	-	-	-	-	-	(0.2)	(0.2)	-		
75	Muir New POD 2018S - AESO Project 1654	-	-	-	-	0.1	-	0.1	-		
76	Seven Generations - Cutbank	0.1	-	-	0.1	-	0.1	-	0.1		
77	Various Other Projects below $0.5 individually	-	-	-	-	-	-	-	-		
78		0.5	(2.0)	(1.9)	0.4	1.2	8.7	9.4	0.5	(11.3)	-120%
79	**TELECOMMUNICATION AND ISOLATED GENERATION**										
80	Isol Gen Projects - Regulated Industrial Sites	6.0	3.8	9.8	-	0.6	5.4	-	6.0	9.8	100%
81	**Total Distribution**	48.4	182.6	179.7	51.3	64.3	200.3	216.2	48.4	(36.5)	-17%
82	**DIRECT GENERAL PP&E**										
83	Tools, Instruments and Equipment	-	1.8	1.7	0.1	0.2	1.2	1.4	-	0.3	21%
84	Communication - Distribution	-	0.1	0.1	-	0.4	0.1	0.5	-	(0.4)	-80%

ATCO Electric
SUMMARY OF CAPITAL EXPENDITURES (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	2021 Actual Opening CWIP	2021 Actual Capital Expenditures	2021 Actual Capital Additions	2021 Actual Closing CWIP	2020 Actual Opening CWIP	2020 Actual Capital Expenditures	2020 Actual Capital Additions	2020 Actual Closing CWIP	Variance to Prior Year ($)	Variance (%)
85	**Software Development Projects**										
86	CC&B Enhancements	-	0.3	-	0.3	-	-	-	-		
87	CIS Program - Common Matters Disallowance	-	(0.4)	-	(0.4)	-	-	-	-		
88	Cloud Migration	-	0.2	0.2	-	-	-	-	-		
89	Customer Care & Billing System	6.0	16.2	-	22.2	0.6	5.4	-	6.0		
90	Customer Engagement	-	-	-	-	-	0.2	0.2	-		
91	Digital	-	0.2	0.2	-	0.6	(0.1)	0.5	-		
92	Digital Commerce	-	-	-	-	-	0.1	0.1	-		
93	Digital Marketing	-	-	-	-	-	0.1	0.1	-		
94	Enterprise IT - Maximo to Oracle Integration (AM)	-	-	-	-	0.3	0.6	0.9	-		
95	Enterprise Technology Strategic Investment	0.0	-	-	0.0	0.1	(0.1)	-	0.0		
96	Field Operations Management	(0.0)	-	-	(0.0)	0.5	(0.5)	-	(0.0)		
97	Financial Consolidation and Close Implementation - Electric	-	0.4	-	0.4	-	-	-	-		
98	Lifecycle Hardware	-	4.1	4.1	-	-	0.3	0.3	-		
99	MDM	7.9	3.3	11.2	-	6.8	1.1	-	7.9		
100	Mobile Work Completion	-	0.6	-	0.6	-	-	-	-		
101	Oracle Middleware	-	-	-	-	0.3	0.2	0.5	-		
102	Oracle Upgrade	-	-	-	-	0.1	-	0.1	-		
103	Scheduling Tool Phase 1	-	0.9	-	0.9	-	-	-	-		
104	Scheduling Tool Phase 2	-	0.3	-	0.3	-	-	-	-		
105	Tablets – Pandemic Support	-	-	-	-	-	0.3	0.3	-		
106	Vegetation Management	-	0.5	0.4	0.1	-	-	-	-		
107	Voice and Data Network Upgrade	-	-	-	-	0.2	0.3	0.5	-		
108	Work Asset Management	13.2	4.6	0.2	17.6	14.6	4.3	5.7	13.2		
109	Lifecycle	-	0.9	0.9	-	-	-	-	-		
110	Kronos Workforce Dimensions	0.2	1.3	-	1.5	-	0.2	-	0.2		
111	Primavera Phase 2	-	-	-	-	-	0.1	0.1	-		
112	ESCI Stage 2	-	7.6	-	7.6	-	-	-	-		
113	Web & Portal Analytics & User Experience- Electric	-	0.4	0.4	-	-	-	-	-		
114	Barcoding - Mobile Materials Application and Hardware- Electric	-	0.2	0.2	-	-	-	-	-		
115	EL Data Management Maturity	-	0.1	-	0.1	-	-	-	-		
116	Enterprise Asset Management - Cyber Security- Electric	-	0.1	0.1	-	-	-	-	-		
117	ATCO Utilities Financial Operational Planning System (OPS) – Electric	-	0.1	-	0.1	-	-	-	-		
118	2021 Oracle Financial Enhancements- Electric	-	0.2	0.2	-	-	-	-	-		
119	Source to Pay Optimization- Electric	-	0.3	0.3	-	-	-	-	-		
120	2021 Salesforce & DevOps Enhancements & Upgrades- Electric	-	0.4	0.4	-	-	-	-	-		
121	Primavera Phase 3 Enhancements	-	0.2	0.2	-	-	-	-	-		
122	Various Other Projects below $0.5 individually	0.1	0.1	0.1	0.1	0.6	1.5	2.0	0.1		
123		27.4	43.1	19.1	51.4	24.7	14.0	11.3	27.4	7.8	69%
124	Transportation Equipment	4.0	8.2	5.3	6.9	9.0	10.4	15.4	4.0	(10.1)	-66%
125	Manning Service Building	-	-	-	-	(1.2)	1.2	-	-		
126	Environmental Assessments	-	0.3	0.2	0.1	-	0.6	0.6	-		
127	Land, Buildings and Structures	0.9	4.8	4.4	1.3	2.5	1.5	3.1	0.9		
128		0.9	5.1	4.6	1.4	1.3	3.3	3.7	0.9	0.9	24%
129		32.3	58.3	30.8	59.8	35.6	29.0	32.3	32.3	(1.5)	-5%
130	IT Common Matters Disallowance	(1.0)	-	(0.4)	(0.6)	(1.9)	-	(0.9)	(1.0)		
131		79.7	240.900	210.1	110.5	98.0	229.300	247.6	79.7	(37.5)	-15%
132	**Net Salvage**			(22.2)				(17.2)			
133	**Additions to Property**			187.9				230.4			

ATCO Electric
CAPITAL ASSETS CONTINUITY SCHEDULE (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	2021 Capital Additions	2020 Capital Additions	Variance to Prior Year $	Variance %	Variance Explanation
1	**Distribution**					
2	Small New Extensions	68.4	85.7	(17.3)	-20.2%	2021 capital additions are lower than 2020 due to less customer activity.
3	Large New Extensions	12.1	29.2	(17.1)	-58.6%	2021 capital additions are lower than 2020 due to less customer activity.
4	Capital Maintenance	70.3	57.4	12.9	22.5%	2021 capital additions are higher than 2020 mainly due to timing of project execution and the addition of the 5L215 Jasper Miette Line Project.
5	Large System Improvements	21.0	34.5	(13.5)	-39.1%	2021 capital additions are lower than 2020 mainly due to timing of project execution.
6	Distribution Contributions to Transmission	(1.9)	9.4	(11.3)	-120.2%	2021 capital additions are lower than 2020 due to a decrease in AESO connection project activity in 2021. The credit is a result of a partial customer refund due to lower final project costs associated with a project prior to April 23, 2021, with a corresponding and equivalent contribution offset.
7	Telecommunications and Isolated Generation	9.8	-	9.8	100.0%	2021 capital additions were higher due to the completion of the Chipewan Lake Interconnection project in 2021.
8	**Total Distribution**	**179.7**	**216.2**			
9	**Direct General PP&E**					
10	Structures and Improvements	4.6	3.7	0.9	24.3%	
11	Transportation Equipment	5.3	15.4	(10.1)	-65.6%	2021 capital additions are lower than 2020 mainly due to supply chain challenges.
12	Tools and Instruments	1.7	1.4	0.3	21.4%	
13	Software	19.1	11.3	7.8	69.0%	2021 capital additions are higher than 2020 mainly due to the completion of the Meter Data Management project in 2021.
14	Other	0.1	0.5	(0.4)	-80.0%	
15	**Total**	**30.8**	**32.3**			
16	Net Salvage	(22.2)	(17.2)			
17	IT Common Matters Disallowance	(0.4)	(0.9)			
18	**Capital Additions**	**187.9**	**230.4**			

ATCO Electric
SUMMARY OF UTILITY INCOME TAX (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	Variance Explanation
1	Net Income Before Tax		112.9	80.2	32.8	41%	**Note 1**
2	Total Permanent Differences		(2.3)	(2.4)	0.1	-4%	
3	Total Timing Differences		(166.3)	(116.4)	(49.9)	43%	**Note 2**
4	Total Differences		(168.7)	(118.8)	(49.9)	42%	
5	Taxable Income		(55.7)	(38.7)	(17.1)	44%	
6	Federal Income Tax Rate		0.2	0.2			
7	Total Federal Income Tax		(8.4)	(5.8)	(2.6)	44%	
8	Provincial Income Tax Rate		0.1	0.1			
9	Total Provincial Income Tax		(4.5)	(3.5)	(1.0)	28%	
10	Current Tax Payable		(12.8)	(9.3)	(3.5)	38%	
11	Large Corporation and Other Tax		-	-	-	0%	
12	Prior Year (over)/under provisions		(0.0)	(5.0)	4.9	-99%	**Note 3**
13	Current Year (over)/under provisions		-	-	-	0%	
14	Other		0.7	0.1	0.6	482%	
15	Current Income Tax		(12.1)	(14.1)	2.0	-14%	
16	Deferred Tax (please describe)		-	-	-	0%	
17	Corporate Income Tax		(12.1)	(14.1)	2.0	-14%	
18	**Income Tax Adjustments**						
19	Tax on disallowed O&M		-	-	-	0%	
20	Other		-	-	-	0%	
			-	-	-	0%	
21	Utility Income Tax				-	0%	
22	Effect of Normalization				-	0%	
23	Utility Income Tax		(12.1)	(14.1)	2.0	-14%	

Note 1 Refer to Schedule 1 and 2.

Note 2 Timing differences are higher than prior year mainly due to higher deductions related to deferral accounts.

Note 3 Prior year (over)/under provision for 2020 is mainly due to 2019 actual filing versus year-end provided for capital related deductions.

Note 4 In accordance with Commission Direction 2 in Decision 22570-D01-2018, the unfunded FIT liability is $442.4M for 2021 and $398.8M for 2020, the year-over-year change is $43.6M.

ATCO Electric

SUMMARY OF CUSTOMERS, ENERGY AND REVENUE (DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

($MILLIONS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	Variance Explanation
1	Residential						
2	Customers - Average		158,694	158,108	586	0.37%	
3	Energy Sales (MWh)		1,138,044	1,132,467	5,577	0.49%	
4	Revenue ($Millions)		227.8	214.3	13.6	6.33%	
5	kWh per Customer		7,171	7,163	8.7	0.12%	
6	Cents/kWh		20.0	18.9	1.1	5.81%	
7	Commercial						
8	Customers - Average		29,609	29,524	85	0.29%	
9	Energy Sales (MWh)		1,983,835	1,972,174	11,661	0.59%	
10	Revenue ($Millions)		178.7	171.7	6.9	4.04%	
11	kWh per Customer		67,001	66,800	201.5	0.30%	
12	Cents/kWh		9.0	8.7	0.3	3.42%	
13	Industrial						
14	Customers - Average		9,390	9,854	(464)	-4.71%	
15	Energy Sales (MWh)		5,558,800	5,328,313	230,487	4.33%	
16	Revenue ($Millions)		312.4	303.2	9.2	3.05%	
17	kWh per Customer		591,965	540,712	51,253.0	9.48%	
18	Cents/kWh		5.6	5.7	(0.1)	-1.22%	
19	R.E.A. Farm						
20	Customers - Average		5,230	5,198	32	0.62%	
21	Energy Sales (MWh)		76,546	77,517	(971)	-1.25%	
22	Revenue ($Millions)		4.4	4.7	(0.4)	-7.52%	
23	kWh per Customer		14,636	14,914	(277.2)	-1.86%	
24	Cents/kWh		5.7	6.1	(0.4)	-6.35%	
25	Company Rural Farm						
26	Customers - Average		27,061	26,941	120	0.44%	
27	Energy Sales (MWh)		466,885	470,921	(4,035)	-0.86%	
28	Revenue ($Millions)		42.6	40.7	1.9	4.61%	
29	kWh per Customer		17,253	17,479	(226)	-1.29%	
30	Cents/kWh		9.1	8.6	0.5	5.52%	
31	Street & Space Lights						
32	Energy Sales (MWh)		20,776	21,637	(861)	-3.98%	
33	Revenue ($Millions)		15.8	17.6	(1.8)	-10.20%	
34	Cents/kWh		76.0	81.2	(5.3)	-6.48%	
35	**DISTRIBUTION TOTAL**						
36	Customers - Average		229,984	229,625	359	0.16%	
37	Energy Sales (MWh)		9,244,887	9,003,030	241,857	2.69%	
38	Power Factor (MVA)		385.3	417.9	(33)	-7.81%	
39	Power Factor Revenue ($Millions)		4.1	4.4	(0)	-7.42%	
40	Revenue ($Millions)		781.7	752.2	29.5	3.92%	
41	Cents/kWh		8.5	8.4	0.1	1.20%	
42	**TRANSMISSION DIRECT CONNECT TOTAL**						
43	Customers - Average		47	46	0	0.90%	
44	Energy Delivered (MWh)		2,731,914	2,490,720	241,193	9.68%	
45	Revenue ($Millions)		86.9	94.6	(7.7)	-8.10%	**Note 1**
46	**TOTAL WIRES DISTRIBUTION RATE REVENUE**						
47	Customers - Average		230,031	229,672	360	0.16%	
48	Energy Delivered (MWh)		11,976,801	11,493,750	483,051	4.20%	
49	Revenue ($Millions)		868.6	846.8	21.8	2.57%	
50	Rider & Other Adjustments		7.1	32.1	(25.0)	-77.8%	
51	Revenue ($Millions)		875.7	878.8	(3.2)	-0.36%	
52	Cents/kWh		7.3	7.4	(0.1)	-1.56%	
53	**Distribution Tariff Revenue**		**875.7**	**878.8**	**(3.2)**	**-0.36%**	
54	**Revenue Offsets**						
55	Affiliate Revenue		10.7	7.3	3.3	45%	
56	Other Revenue		7.9	6.0	1.9	32%	
57	**Total Revenue Offsets**		**18.6**	**13.3**	**5.2**	**39%**	**Note 2**

Note 1 Transmission Direct Connect revenue in 2021 was lower mainly due a decrease in AESO DTS rates.
Note 2 Revenue Offsets are higher in 2021 mainly due to an increase in affiliate cost of goods sold.

ATCO Electric
ANALYSIS OF AFFILIATE COST OF GOODS SOLD (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Affiliate	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)	Variance Explanation
1	**Distribution Affiliate Cost of Goods Sold**						
2	Shared Office Services - Cold Lake	ATCO Gas	0.3	0.3	(0.0)	-5.5%	
3	Customer Care and Billing Services	ATCO Gas	0.4	0.4	(0.0)	-6.6%	
4	Project Services	ATCO Gas	0.0	0.0	(0.0)	-35.0%	
5	Engineering and Project Services	ATCO Power Canada Limited	-	-	-	0.0%	
6	Project and Asset Management Services	ATCO Power 2010 Ltd.	1.6	2.9	(1.3)	-46.1%	**Note 1**
7	Billing and Process Improvements	ATCO Energy	-	-	-	0.0%	
8	Project Services	ATCO Infrastructure Solutions Ltd.	5.4	1.4	4.0	276.8%	**Note 2**
9	Environmental Reclamation Services	ATCO Investments Ltd.	0.1	0.1	0.0	14.8%	
10	Items individually less than $0.1 million	Various	0.1	0.2	(0.1)	-37.4%	
11			8.0	5.4	2.6	47.3%	
12	**Corporate Affiliate Cost of Goods Sold**						
13	Administrative Services	ATCO Electric (Yukon)	0.8	0.7	0.1	20.4%	
14	Administrative Services	Northland Utilities (NWT) Limited	0.4	0.3	0.1	15.1%	
15	Administrative Services	Northland Utilities (Yellowknife) Limited	0.4	0.4	0.1	14.8%	
16	Fleet Maintenance	ATCO Gas	0.9	0.5	0.4	66.5%	
17	Fleet Maintenance	ATCO Pipelines	0.1	-			
18	Fleet Maintenance	ATCO Energy Solutions	0.1	-	0.1	0.0%	
19			2.7	1.9	0.8	40.1%	
20	**Total Affiliate Cost of Goods Sold**		**10.7**	**7.3**	**3.3**	**45.4%**	

Note 1 Affiliate cost of goods sold were lower than prior year due to higher services required in 2020.

Note 2 Affiliate cost of goods sold were higher than prior year due to higher project services required as a result of the successful bid related to the Puerto Rico Electricity System.

ATCO Electric
SUMMARY OF PAYROLL AND MANPOWER STATISTICS (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

SALARIES, WAGES AND EMPLOYEE BENEFITS

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year ($)	Variance (%)
1	Salaries, Wages and Employee Benefits					
2	Distribution Operations		38.5	38.2	0.3	0.8%
3	Distribution Capital		74.7	75.9	(1.2)	-1.6%
4	Distribution Corporate - Operations		16.9	15.7	1.2	7.3%
5	Distribution Corporate - Capital		8.1	8.2	(0.1)	-1.6%
6	**Salaries, Wages and Employee Benefits Charged to Utility Operations**		**138.2**	**138.0**	**0.1**	**0.1%**

EMPLOYEE ALLOCATION

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Prior Year	Variance (%)
7	Manpower Statistics					
8	Total Regular Employees (FTE's)		821.7	836.0	(14.3)	-1.7%
9	Total Temporary Employees (FTE's)		40.3	31.8	8.5	26.8%
10	**Total Manpower**		**862.1**	**867.8**	**(5.8)**	**-0.7%**

ATCO Electric
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS (DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
($MILLIONS)

Line No.	Description	Cross-Reference	2021 Opening Balance	Adds	Funding	Payments/ Claims	Prior Year Adjustments	Ending Balance
1	List of Reserve/Deferral Accounts							
2	Z-Factor (Fort McMurray Fires - 2016)		0.0	-	-	-	-	0.0
3	**Total Deferral Accounts**		0.0	-	-	-	-	0.0
4	AUC Assessment Fees/Intervener Hearing Costs		(0.4)	0.9	(1.3)	0.2	(0.1)	(0.7)
5	AESO Load Settlement		0.1	0.2	(0.2)	-	(0.0)	0.1
6	Tax Deferral on Capital Repair Costs		-	-	-	-	-	-
7	Deducting Deferrals for Income Tax		(3.0)	(14.6)	-	(1.8)	(0.0)	(19.4)
8	Mandatory Evacuation Waived fees		-	-	-	-	-	-
9	**Total Y-Factors**		(3.3)	(13.5)	(1.5)	(1.6)	(0.2)	(20.0)

ATCO Electric

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS (TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($MILLIONS)

Line No.	Description	Cross-Reference	Audited Financial Statements	Transmission Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Adjustments	Distribution Utility Total
			(see attached)					
1	**Revenues**		**1,231.0**	**732.7**	**(442.7)**	**941.0**		
2	Reclass of Non-Pool Energy to Cost of Sales and Fuel						3.7	
3	Reclass of Amortization of Contributions to Depreciation						(27.6)	
4	Elimination of Recoveries from ATCO Electric Transmission						(4.7)	
5	Reclassification of Revenue Offsets						(18.6)	
6	Eliminate Non-Utility Revenues						(20.9)	
7	Non IFRS Deferral Revenue Adjustment						43.5	
8	Non IFRS Tariff Revenue Adjustment						2.5	
9	Other						0.3	
10		Sch 1.0-D	1,231.0	732.7	(442.7)	941.0	(21.8)	**919.2**
11	**Cost of Sales**							
12	Reclass of Non-Pool Energy to Cost of Sales and Fuel			**-**	**(433.1)**	**433.1**	3.7	
13	Other						(0.3)	
14			-	-	(433.1)	433.1	3.4	**436.5**
15	**Fuel**							
16	Fuel Costs		**3.1**	**3.1**	**-**	**0.0**		
17	Reclass of Non-Pool Energy to Cost of Sales and Fuel						-	
18			3.1	3.1	-	0.0	-	**0.0**
19	**Operating and Maintenance**		**441.7**	**216.8**	**0.9**	**224.0**		
20	Elimination of ATCO Electric Transmission COGS						(4.7)	
21	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						-	
22	Non-Utility Costs						(25.5)	
23	Credit Facility Reclass From Financing						(10.5)	
24	Reclass of Non-Pool Energy to Cost of Sales and Fuel						1.6	
25	Other						(0.0)	
26		Sch 1.0-D	441.7	216.8	0.9	224.0	(39.1)	**184.8**
27	**Depreciation and Amortization**		**311.6**	**185.5**	**(8.0)**	**134.1**		
28	Reclass of Amortization of Contributions to Depreciation						(27.6)	
29	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						29.3	
30	Remove Depreciation on Non-Utility assets						(4.5)	
31	IT Common Matters 20514-D02-2019 Indirect Disallowance						(0.1)	
32	IT Common Matters 20514-D02-2019 Direct Disallowance						(0.5)	
33	Other						0.6	
34		Sch 1.0-D	311.6	185.5	(8.0)	134.1	(2.7)	**131.3**
35	**Income Tax**		**65.0**	**47.7**	**(0.6)**	**17.9**		
36	Tax on Adjustments	Note 2					(30.1)	
37		Sch 1.0-D	65.0	47.7	(0.6)	17.9	(30.1)	**(12.1)**
38	**Revenue Offsets**		**-**	**-**	**-**	**-**		
39	Reclassification from Revenues						18.6	
40		Sch 1.0-D	-	-	-	-	18.6	**18.6**
41	**Return**		**409.5**	**279.5**	**(2.0)**	**132.0**		
42	Adjustments	Note 1					65.3	
43			409.5	279.5	(2.0)	132.0	65.3	**197.2**
44	**Note 1 - Return Adjustments**							
45	Long Term Debt & Other		**218.8**	**152.2**	**-**	**66.6**		
46	Adjustment for IFRS IDC Treatment						3.2	
47	Eliminate Dividend Income from Subsidiary Companies						8.5	
48	Deferred Pension Costs						(0.3)	
49	Deferred OPEB Costs						(0.2)	
50	Credit facility Reclass to O&M						(1.6)	
51	Remove Financing of Non-Utility Assets						(1.5)	
52	Financing Other						(2.4)	
53			218.8	152.2	-	66.6	5.6	**72.1**
54	Preferred Shares		**-**	**-**	**-**	**-**		
55	Include Preferred Share Accrual for Utility Earnings						1.6	
56			-	-	-	-	1.6	**1.6**
57	Return on Equity		**190.7**	**127.3**	**(2.0)**	**65.4**		
58	Return on Equity Adjustments	Note 2					58.1	
59			190.7	127.3	(2.0)	65.4	58.1	**123.5**
60	**Total Return Adjustments**		**409.5**	**279.5**	**(2.0)**	**132.0**	**65.3**	**197.2**
61	**Note 2 - Return on Equity Adjustments**					Before Tax	(Return) After Tax	Tax Impact
62	**Financing and Subs**							
63	Preferred Dividends					(1.6)	(1.6)	-
64	IDC					(3.2)	(2.4)	(0.8)
65	Interest and Other					(4.0)	(5.1)	1.0
66	**Income Tax**							
67	Income Tax (Future Tax for IFRS)					-	29.1	(29.1)
68	Income Tax (T2S1 Adjustments Due to IFRS)					-	9.4	(9.4)
69	Income Tax (Book to Filing Adjustments)					-	0.2	(0.2)
70	**Other Income Statement Items**							
71	Revenue Tax Impact					25.4	19.6	5.8
72	O&M Tax Impact					36.3	28.0	8.4
73	Depreciation Tax Impact					(24.9)	(19.2)	(5.7)
74	Other					-	0.1	(0.0)
75						**28.0**	**58.1**	**(30.1)**

ATCO Electric

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(Transmission and Distribution)
FOR THE YEAR ENDED DECEMBER 31, 2021
BALANCE SHEET ITEMS
($000s)

Line No.	Description	Cross-Reference	Audited Financial Statements (see attached)	Adjustments	Total
1	**Assets**				
2	Current Assets				
3	Cash and short term investments		18.5	-	18.5
4	Accounts receivable		147.6	(0.4)	147.2
5	Income taxes		0.2	757.6	757.8
6	Inventories		3.8	-	3.8
7	Prepaid expenses		6.2	-	6.2
8	Property, plant and equipment		9,853.7	(1,844.9)	8,008.8
9	Investments		131.5	(16.5)	114.9
10	Regulatory assets		-	103.6	103.6
11	Deferred financing charges		-	27.2	27.2
12	Other		-	-	-
13	**Total Assets**		**10,161.4**	**(973.4)**	**9,188.0**
14	**Liabilities**				
15	Current Liabilities				
16	Bank Indebtedness		-	-	-
17	Short term advances from parent and affiliated corporations		57.7	-	57.7
18	Accounts payable and accrued liabilities		160.3	(0.6)	159.7
19	Owing to parent and affiliated corporations		72.7	-	72.7
20	Income taxes payable		-	0.0	0.0
21	Regulatory liabilities		-	-	-
22	Long term debt		50.0	(50.0)	0.0
23	Future income taxes		949.5	(5.8)	943.7
24	Regulatory Liabilities		-	-	-
25	Long term debt		5,006.3	(26.8)	4,979.5
26	Other		1,107.1	(1,041.4)	65.7
27	**Total Liabilities**		**7,403.6**	**(1,124.6)**	**6,279.0**
28	**Equity**				
29	Equity preferred shares to Parent Corporation		98.3	1.7	100.0
30	Class A and Class B shares owner's equity				
31	Class A and Class B shares		1,212.4	-	1,212.4
32	Retained earnings		1,447.1	149.4	1,596.6
33	**Total Equity**		**2,757.9**	**151.1**	**2,909.0**
34	**Total Liabilities and Share Owner's Equity**		**10,161.4**	**(973.4)**	**9,188.0**

Note 1 In 2021, the International Financial Reporting Interpretations Committee (IFRIC) of the International Accounting Standards Board (IASB) published guidance regarding the accounting for costs incurred in implementing cloud computing arrangements. The IFRIC specifically addresses how to account for costs of configuring or customizing a supplier’s application software in a Software as a Service (SaaS) arrangement. The IFRIC concluded that these costs should be expensed, given the software being configured or customized is not owned or controlled by the customer. Implementation of the IFRIC guidance was required to be implemented by December 31, 2021 and applied retroactively. Note that no similar guidance exists in US GAAP resulting in different accounting results for many Alberta peer utilities reporting under US GAAP.

ATCO Electric examined this issue and determined that approximately 2 percent of the ATCO Electric SaaS arrangement costs were impacted. However, given that the impact of this IFRIC guidance is negligible for rate base (the cumulative impact of approximately $1.2 million of ATCO Electric’s $2.6 billion rate base), ATCO Electric continues to reflect costs of SaaS arrangements in this COS consistent with other Alberta Utilities reporting in US GAAP.

ATCO Electric

SUMMARY OF PENSION PLAN CONTRIBUTIONS (DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

($MILLIONS)

Line No. ATCO Electric has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

1 **The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in**
2 **its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:**

3 **i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the**
4 **unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed**
5 **as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.**

6 **2021 Actual**

Line No.		Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
8		Service Amount	Special Payment	Service Amount	
9	**ATCO Electric (Note 1)**	1.7	-	4.9	**6.6**
10	**ATCO Unregulated**	2.5	-	6.1	**8.6**

11 Note 1 - The actual defined benefit and defined contribution service amounts along with the special payment do not include amounts that are allocated from the ATCO Head office.
12 This amount includes COLA at 100%.

13 **ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts**
14 **contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.**

15 Note: Under Performance Based Regulation, ATCO Electric Distribution no longer has deferral account treatment for special payment pension contributions.

16 **iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated**
17 **impact of any filings on the pension funding requirements of each of the ATCO Utilities.**

18 The Mercer 2020 CU Pension Plan Reort dated August 11, 2021 was filed with the Superintendent of Pensions. The required pension funding contributions for ATCO Electric
19 Distribution beginning January 1, 2021 are $1.7 million for current service and $0.0 million for special payments.

ATCO ELECTRIC LTD.

NON-CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021

Independent auditor's report

To the Shareowner of ATCO Electric Ltd.

Our opinion

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of ATCO Electric Ltd. (the Company) as at December 31, 2021 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited
The Company's non-consolidated financial statements comprise:

- the non-consolidated statement of earnings for the year ended December 31, 2021;
- the non-consolidated statement of comprehensive income for the year ended December 31, 2021;
- the non-consolidated balance sheet as at December 31, 2021;
- the non-consolidated statement of changes in equity for the year ended December 31, 2021;
- the non-consolidated statement of cash flow for the year ended December 31, 2021; and
- the notes to the non-consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the non-consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the non-consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Stantec Tower, 10220 103 Avenue NW, Suite 2200, Edmonton, Alberta, Canada T5J 0K4
T: +1 780 441 6700, F: +1 780 441 6776

Responsibilities of management and those charged with governance for the non-consolidated financial statements

Management is responsible for the preparation and fair presentation of the non-consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of non-consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the non-consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the non-consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the non-consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these non-consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the non-consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the non-consolidated financial statements, including the disclosures, and whether the non-consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
April 29, 2022

TABLE OF CONTENTS

NON-CONSOLIDATED STATEMENT OF EARNINGS

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Revenues	4	**1,230,980**	1,217,919
Costs and expenses			
Salaries, wages and benefits		**(90,863)**	(92,471)
Plant and equipment maintenance		**(78,409)**	(77,179)
Fuel costs		**(3,137)**	(3,499)
Depreciation and amortization	8,9	**(311,608)**	(298,731)
Franchise fees		**(31,982)**	(30,194)
Property and other taxes		**(51,815)**	(50,810)
Other	5	**(188,610)**	(147,609)
		(756,424)	(700,493)
Dividend income from subsidiary companies	10	**8,480**	8,852
Operating profit		**483,036**	526,278
Interest income		**5,815**	5,442
Interest expense	6	**(233,089)**	(229,665)
Net finance costs		**(227,274)**	(224,223)
Earnings before income taxes		**255,762**	302,055
Income tax expense	7	**(65,048)**	(73,093)
Earnings for the year		**190,714**	228,962

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2021**	**2020**
Earnings for the year		**190,714**	228,962
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	12	**6,494**	(4,240)
Comprehensive income for the year		**197,208**	224,722

(1) Net of income taxes of $(2) million for the year ended December 31, 2021 (2020 - $1 million).

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2021	2020
ASSETS			
Current assets			
Cash		**15,467**	4,854
Short-term advances to parent company	23	**2,999**	29,000
Accounts receivable and contract assets	13	**144,274**	135,538
Accounts receivable from parent and affiliate companies	13, 23	**3,306**	5,091
Inventories		**3,795**	4,161
Income taxes recoverable		**167**	719
Prepaid expenses and other current assets		**6,224**	6,281
		176,232	185,644
Non-current assets			
Property, plant and equipment	8	**9,498,386**	9,489,268
Intangibles	9	**355,313**	330,535
Investment in subsidiary companies	10	**16,335**	16,335
Long-term advances to subsidiary companies	23	**104,023**	104,023
Other assets		**11,113**	11,735
Total assets		**10,161,402**	10,137,540
LIABILITIES			
Current liabilities			
Bank indebtedness		**3,021**	–
Short-term advances from parent and affiliated companies	23	**54,700**	109,000
Accounts payable and accrued liabilities		**101,003**	100,020
Accounts payable to parent and affiliate companies	23	**72,670**	57,340
Long-term debt	11, 23	**50,010**	101,000
Provisions and other current liabilities		**59,287**	28,216
		340,691	395,576
Non-current liabilities			
Deferred income tax liabilities	7	**949,465**	885,477
Retirement benefit obligations	12	**59,127**	67,267
Customer contributions	13	**1,046,609**	980,874
Long-term debt	11, 23	**5,006,263**	4,895,922
Other liabilities		**1,396**	1,080
Total liabilities		**7,403,551**	7,226,196
EQUITY			
Equity preferred shares	14, 23	**98,280**	141,968
Class A and Class B share owner's equity			
Class A and Class B shares	15	**1,212,428**	1,212,428
Retained earnings		**1,447,143**	1,556,948
		2,659,571	2,769,376
Total equity		**2,757,851**	2,911,344
Total liabilities and equity		**10,161,402**	10,137,540

See accompanying Notes to Non-consolidated Financial Statements.

DIRECTOR

DIRECTOR

NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
December 31, 2019		1,212,428	141,968	1,652,117	–	3,006,513
Earnings for the year		–	–	228,962	–	228,962
Other comprehensive loss		–	–	–	(4,240)	(4,240)
Loss on retirement benefits transferred to retained earnings	12	–	–	(4,240)	4,240	–
Dividends	14,15	–	–	(319,891)	–	(319,891)
December 31, 2020		1,212,428	141,968	1,556,948	–	2,911,344
Earnings for the year		–	–	**190,714**	–	**190,714**
Other comprehensive loss		–	–	–	**6,494**	**6,494**
Gain on retirement benefits transferred to retained earnings	12	–	–	**6,494**	**(6,494)**	–
Redemption of equity preferred shares	14	–	**(43,688)**	**(26)**	–	**(43,714)**
Dividends	14,15	–	–	**(306,987)**	–	**(306,987)**
December 31, 2021		**1,212,428**	**98,280**	**1,447,143**	–	**2,757,851**

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Operating activities			
Earnings for the year		**190,714**	228,962
Adjustments to reconcile earnings to cash flows from operating activities	16	**650,246**	606,738
Changes in non-cash working capital	16	**59,379**	(8,169)
Cash flows from operating activities		**900,339**	827,531
Investing activities			
Additions to property, plant and equipment	8	**(281,872)**	(309,636)
Proceeds on disposal of property, plant and equipment		**242**	–
Additions to intangibles	9	**(48,943)**	(36,725)
Issue of long-term advances to subsidiary companies		**–**	(4,200)
Repayment of long-term advances to subsidiary companies		**–**	1,500
Changes in non-cash working capital	16	**(19,530)**	(14,832)
Other		**1,069**	651
Cash flows used in investing activities		**(349,034)**	(363,242)
Financing activities			
Issue of long-term debt	11	**160,600**	25,625
Repayment of long-term debt		**(101,000)**	(38,243)
Repayment of lease liability		**(327)**	(319)
Redemption of equity preferred shares to parent company	14	**(43,714)**	–
Dividends paid on equity preferred shares		**(4,985)**	(5,692)
Dividends paid to Class A and Class B share owner		**(302,002)**	(314,199)
Interest paid		**(222,432)**	(226,281)
Other		**(1,554)**	(498)
Cash flows used in financing activities		**(515,414)**	(559,607)
Increase (decrease) in cash position		**35,891**	(95,318)
Beginning of year		**(75,146)**	20,172
End of year	16	**(39,255)**	(75,146)

See accompanying Notes to Non-consolidated Financial Statements.

NOTES TO NON-CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2021

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

ATCO Electric is engaged in the transmission and distribution of electric energy in the Province of Alberta. Its registered office and head office is at 19th Floor, 10035 -105 Street NW, Edmonton, Alberta, T5J 2V6. ATCO Electric is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these non-consolidated financial statements, "the Company" means ATCO Electric Ltd.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The non-consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Pursuant to the Company's regulatory obligation to the Alberta Utilities Commission (AUC) and interested parties, the Company is obliged to provide detailed information relating solely to the electric utility and not relating to non-regulated subsidiaries, nor electric utilities regulated by other jurisdictions. The Company has, therefore, exercised the exemption from full consolidation of its investment in subsidiary companies available under IAS 27 *Separate Financial Statements*. As a result, the Company’s investment in subsidiary companies and joint arrangements are carried at the original cost and the earnings of the subsidiary companies are reflected in the determination of earnings of the Company only to the extent of dividends received from the subsidiaries. The Company's proportionate interest in balances and transactions of joint arrangements have been excluded from these non-consolidated financial statements. Consolidated financial statements of the Company’s immediate parent, CU Inc., that comply with IFRS are available for public use. CU Inc. is incorporated in Canada and its registered office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4.

Management authorized these non-consolidated financial statements for issue on April 29, 2022.

BASIS OF MEASUREMENT

The non-consolidated financial statements are prepared on a historic cost basis, except for retirement benefit obligations which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 24.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The non-consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the non-consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Estimates and judgments are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 20.

ADOPTION OF NEW ACCOUNTING INTERPRETATION

In April 2021, the IFRS Interpretations Committee published a final agenda decision with respect to recognition of certain configuration and customization expenditures related to cloud computing with retrospective application. Costs that do not meet the capitalization criteria should be expensed as incurred. Any changes resulting from the decision were required to be implemented by December 31, 2021.

As a result of the review of the impact of the decision on the financial statements, the Company recorded a decrease to intangible assets of $1.8 million with a corresponding increase to other expenses in the statement of earnings (Note 9).

3. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares,
- one-time gains and losses,
- impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of earnings used by the Chief Operating Decision Maker (CODM) to assess performance and allocate resources. Other accounts in the non-consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

	2021	2020
Adjusted earnings	**302,910**	304,577
Transition of managed IT services	**(13,657)**	(21,533)
AUC enforcement proceeding	**(41,133)**	–
Restructuring costs	**(756)**	(3,493)
Rate-regulated activities	**(53,456)**	(45,204)
IT Common Matters decision	**(8,179)**	(11,077)
Dividends on equity preferred shares	**4,985**	5,692
Earnings for the year	**190,714**	228,962

Transition of managed IT services

In 2020, Canadian Utilities Limited, signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) (subsequently novated to Kyndryl Canada Ltd.) to provide managed information technology (IT) services. These services were previously provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring December 2024. The transition of the managed IT services from Wipro to IBM commenced February 1, 2021 and was complete at December 31, 2021. In addition, the Company recognized transition costs of $18 million ($14 million after-tax) in 2021. The transition costs related to activities to transfer the managed IT services from Wipro to IBM. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

In 2020, the Company recognized an onerous contract provision of $28 million ($22 million after-tax), which represents management's best estimate of the costs to exit the Wipro MSA. The provision is included in provisions and other current liabilities in the non-consolidated balance sheets. The onerous contract provision is not in the normal course of business and has been excluded from adjusted earnings.

Alberta Utilities Commission (AUC) enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $41 million (after-tax) due to the potential outcome of the proceeding. As this proceeding is not in the normal course of business, these costs have been excluded from adjusted earnings.

Restructuring costs

In 2021, the Company recorded restructuring costs of $0.7 million, after-tax, that were not in the normal course of business. These costs mainly related to staff reductions and associated severance costs (2020 - $3.5 million).

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the Company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company recognizes revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2021	2020
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**32,683**	26,815
Revenues to be billed in future periods		
Deferred income taxes (2)	**(49,211)**	(52,211)
Distribution rate relief (3)	**(48,232)**	–
Regulatory decisions received	**13,358**	8,610
Settlement of regulatory decisions and other items (4)	**(2,054)**	(28,418)
	(53,456)	(45,204)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by the Company.

(3) In 2021, in response to the ongoing COVID-19 Pandemic, ATCO Electric Distribution applied for interim rate relief for customers to hold current distribution base rates in place. Following approval by the AUC, ATCO Electric Distribution recorded a decrease in earnings of $48 million. This will be recovered from customers in 2022 and 2023.

(4) In 2020, ATCO Electric Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. The significant regulatory decisions impacting adjusted earnings during 2021 are provided below.

	Decision	Amount	Description
1.	2020-2022 ATCO Electric General Tariff Application (GTA) Compliance Decision	**6,296**	In October 2019, the Company filed a GTA for its Electric Transmission operations for 2020, 2021, and 2022. On April 19, 2021, the AUC issued its Compliance decision related to the 2020-2022 GTA resulting in a reduction in adjusted earnings of $6.3 million recorded in 2021.
2	2018-2019 ATCO Electric General Tariff Application (GTA) Compliance Decision	**7,062**	In June 2017, the Company filed a GTA for its Electric Transmission operations for 2018 and 2019. On August 12, 2020, the AUC issued its Compliance decision related to the 2018-2019 GTA resulting in a reduction in adjusted earnings of $7.1 million recorded in 2021.

The significant regulatory decisions impacting adjusted earnings during 2020 are provided below.

	Decision	Amount	Description
1.	ATCO Electric Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances	5,721	In March 2019, Electric Transmission filed an application seeking the approval of approximately $2.2 billion of capital additions from transmission projects with in-service dates between 2015-2017. In November 2020, Electricity Transmission received a decision regarding its 2019 application for the disposal of its 2015-2017 transmission deferral accounts and annual filing adjustment balances. The reduction in adjusted earnings resulting from the decision was $5.7 million, which relates to the period January 1, 2015 to December 31, 2017.
2.	2018-2019 ATCO Electric General Tariff Application (GTA) Compliance Decision	2,889	In June 2017, the Company filed a GTA for its Electric Transmission operations for 2018 and 2019. On August 12, 2020, the AUC issued its Compliance decision related to the 2018-2019 GTA resulting in a reduction in adjusted earnings of $2.9 million recorded in 2020.

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by CU Inc.'s parent, Canadian Utilities Limited, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2021 was $8.2 million (2020 - $11.1 million).

4. REVENUES

The significant categories of revenues recognized during the year are as follows:

	2021	2020
Distribution revenue [1]	**408,004**	394,353
Transmission revenue	**683,023**	695,305
Customer contributions *(Note 13)*	**30,530**	32,336
Franchise fees & property tax revenues	**32,128**	29,909
Other	**77,295**	66,016
	1,230,980	1,217,919

(1) For the year ended December 31, 2021, revenues from distribution services include $58.1 million of unbilled revenues (2020 - $62.0 million). At December 31, 2021, $58.1 million of the unbilled trade accounts receivables are included in accounts receivable and contract assets (2020 - $62.0 million).

5. OTHER COSTS AND EXPENSES

Other costs and expenses comprise the following:

	2021	2020
Professional fees, services and contractors	**5,919**	6,882
Technology expenses	**27,724**	26,155
Insurance	**7,256**	6,538
Travel and meals	**1,273**	1,594
Office services and other costs	**737**	810
Head office fees	**43,858**	44,445
Licenses	**7,396**	7,202
Corporate license fees	**6,428**	5,155
Loss on disposal	**(158)**	–
Telecommunications	**1,612**	1,534
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**17,631**	28,002
Provision on AUC enforcement proceeding (*Note 3, 21*)	**43,037**	–
Other	**25,897**	19,292
	188,610	147,609

6. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2021	2020
Long-term debt	**228,060**	230,595
Amortization of deferred financing charges	**1,307**	1,159
Other	**4,039**	3,042
	233,406	234,796
Less: interest capitalized *(Notes 8, 9)*	**(317)**	(5,131)
	233,089	229,665

Borrowing costs capitalized to property, plant and equipment and intangibles during 2021 were calculated by applying a weighted average interest rate of 4.58 per cent (2020 - 4.52 per cent) to expenditures on qualifying assets.

7. INCOME TAXES

INCOME TAX EXPENSE

The income tax rate for 2021 is 23.0 per cent (2020 - 24.0 per cent).

The components of income tax expense for the year ended December 31 are summarized below.

	2021	2020
Current income tax expense		
Expenses for the year	**1,994**	1,575
Adjustment in respect of prior years	**1,006**	–
	3,000	1,575
Deferred income tax expense		
Reversal of temporary differences	**62,389**	65,683
Change in income taxes resulting from decrease in provincial corporate tax rate	**–**	4,960
Adjustment in respect of prior years	**(341)**	875
	62,048	71,518
	65,048	73,093

The reconciliation of statutory and effective income tax expense for the year ended December 31 is as follows:

	2021		2020	
Earnings before income taxes	**255,762**	**%**	302,055	%
Income taxes, at statutory rates	**58,825**	**23.0**	72,493	24.0
Dividend income	**(1,950)**	**(0.8)**	(2,124)	(0.7)
Non-deductible differences	**7,116**	**2.8**	–	–
Part VI.I tax net of transfer benefit	**389**	**0.1**	364	0.1
Change in income taxes resulting from decrease in provincial corporate tax rate	**–**	**–**	4,960	1.6
Statutory and deferred tax variance	**–**	**–**	(2,922)	(1.0)
Other	**668**	**0.3**	322	0.1
	65,048	**25.4**	73,093	24.1

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations and Other	Total
December 31, 2019	830,912	45,305	(53,849)	(7,159)	815,209
Charge (credit) to earnings	80,991	(187)	(3,907)	(10,339)	66,558
Credit to other comprehensive income	–	–	–	(1,250)	(1,250)
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	4,960	–	4,960
December 31, 2020	911,903	45,118	(52,796)	(18,748)	885,477
Charge (credit) to earnings	**66,262**	**(8,023)**	**3,015**	**794**	**62,048**
Credit to other comprehensive income	**–**	**–**	**–**	**1,940**	**1,940**
December 31, 2021	**978,165**	**37,095**	**(49,781)**	**(16,014)**	**949,465**

The Company does not expect its deferred income tax liabilities to reverse within the next twelve months (2020 - nil).

At December 31, 2021, the Company had $217 million of non-capital tax losses and credits which expire between 2035 and 2041. The Company recognized deferred income tax assets of $50 million for these losses and credits.

8. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2019	11,020,655	409,260	185,048	542,218	12,157,181
Additions	1,003	–	321,832	–	322,835
Transfers	265,750	2,662	(295,752)	27,340	–
Retirements and disposals	(25,856)	(5,413)	–	(17,793)	(49,062)
December 31, 2020	11,261,552	406,509	211,128	551,765	12,430,954
Additions	**100**	–	**288,922**	–	**289,022**
Transfers	**264,351**	**5,110**	**(287,494)**	**18,033**	–
Retirements and disposals	**(57,667)**	**2,006**	–	**(15,170)**	**(70,831)**
Related party transfers	–	–	–	**(63)**	**(63)**
December 31, 2021	**11,468,336**	**413,625**	**212,556**	**554,565**	**12,649,082**
Accumulated depreciation					
December 31, 2019	2,395,765	76,860	–	245,505	2,718,130
Depreciation	228,754	10,223	–	33,641	272,618
Retirements and disposals	(25,856)	(5,413)	–	(17,793)	(49,062)
December 31, 2020	2,598,663	81,670	–	261,353	2,941,686
Depreciation	**235,741**	**12,529**	–	**33,271**	**281,541**
Retirements and disposals	**(59,400)**	**2,102**	–	**(15,170)**	**(72,468)**
Related party transfers	–	–	–	**(63)**	**(63)**
December 31, 2021	**2,775,004**	**96,301**	–	**279,391**	**3,150,696**
Net book value					
December 31, 2020	8,662,889	324,839	211,128	290,412	9,489,268
December 31, 2021	**8,693,332**	**317,324**	**212,556**	**275,174**	**9,498,386**

In 2021, the additions to property, plant and equipment included a write-down of interest capitalized during construction of $1.8 million mainly due to canceled projects. In 2020, interest capitalized during construction included in the additions to property, plant and equipment was $3.9 million.

9. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Work-in-Progress	Total
Cost				
December 31, 2019	195,180	229,416	34,565	459,161
Additions	–	–	36,725	36,725
Transfers	22,950	11,819	(34,769)	–
Retirements	(22,451)	–	–	(22,451)
December 31, 2020	195,679	241,235	36,521	473,435
Additions	–	–	**48,943**	**48,943**
Transfers	**15,931**	**5,550**	**(21,481)**	–
Retirements	**(14,200)**	**(58)**	–	**(14,258)**
December 31, 2021	**197,410**	**246,727**	**63,983**	**508,120**
Accumulated amortization				
December 31, 2019	102,610	32,154	–	134,764
Amortization	26,064	4,523	–	30,587
Retirements	(22,451)	–	–	(22,451)
December 31, 2020	106,223	36,677	–	142,900
Amortization	**21,262**	**2,903**	–	**24,165**
Retirements	**(14,200)**	**(58)**	–	**(14,258)**
December 31, 2021	**113,285**	**39,522**	–	**152,807**
Net book value				
December 31, 2020	89,456	204,558	36,521	330,535
December 31, 2021	**84,125**	**207,205**	**63,983**	**355,313**

In 2021, the additions to intangibles included $2.1 million of interest capitalized during construction (2020 - $1.2 million).

In 2021, the Company recorded a decrease to intangibles of $1.8 million with a corresponding increase to other expenses in the statement of non-consolidated statement of earnings as a result of the review of the impacts of IFRIC on recognition of certain configuration and customization expenditures related to cloud computing costs (Note 2).

10. INVESTMENTS

The investment in subsidiary companies at December 31 is as follows:

Investee	Principal place of business	Percentage ownership	2021	2020
ATCO Electric Yukon	Whitehorse, Yukon	100%	**12,171**	12,171
Norven Holdings Inc.	Edmonton, Alberta	100%	**4,164**	4,164
			16,335	16,335

In 2021, the Company received $8.5 million in cash dividends from its subsidiaries (2020 - $8.9 million).

The Company has an 80 per cent interest in ATCO-Valard Design Build Joint Venture. ATCO-Valard Design Build Joint Venture is an unincorporated joint arrangement between the Company and Valard Construction LP, a subsidiary of Quanta Services, Inc., for the purpose of developing, designing and building the Fort McMurray West 500-kilovolt (kV) Transmission Project.

11. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2021	2020
Debentures - unsecured [1]	4.505% (2020 - 4.553%)	**5,076,644**	5,017,643
Other long-term obligation, due June 2023 - unsecured [2]	2.450% (2020- 2.450%)	**6,870**	6,270
Less: deferred financing charges		**(27,241)**	(26,991)
		5,056,273	4,996,922
Less: amounts due within one year		**(50,010)**	(101,000)
		5,006,263	4,895,922

(1) Interest rate is the average effective interest rate weighted by principal amounts outstanding.

(2) During 2021, the expiry date of the CU Inc. other long-term obligation was extended from June 2022 to June 2023.

Debenture Issuances

During 2021, the Company issued $160 million of 3.174 per cent debentures maturing on September 5, 2051 (2020 - $25.0 million of 2.609 per cent debentures maturing on September 28, 2050).

During 2021, the Company repaid $101 million of 4.801 per cent debentures on November 22, 2021 (2020 - $38.2 million of 11.770 per cent debentures on November 30, 2020).

12. RETIREMENT BENEFITS

The Company, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-registered non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2021.

Information about the Company's participation in the group benefit plans is as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**5,629**	**1,912**	9,030	1,919
Defined contribution plans cost	**8,620**	**–**	8,626	–
Total cost	**14,249**	**1,912**	17,656	1,919
Less: capitalized	**9,405**	**1,259**	11,578	1,259
Net cost recognized	**4,844**	**653**	6,078	660
Accrued benefit obligations				
Beginning of year	25,167	42,100	21,836	37,533
Defined benefit plan cost	**5,629**	**1,912**	9,030	1,919
Benefit payments	**(3,004)**	**(1,190)**	(3,354)	(1,118)
Contributions to defined benefit plans	**(3,052)**	**–**	(4,088)	–
Actuarial (gains) losses	**(3,670)**	**(4,765)**	1,743	3,766
End of year	**21,070**	**38,057**	25,167	42,100

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Average compensation increase for the year	**2.25 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.16 %**	**3.16 %**	2.58 %	2.58 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.05 %**	n/a	5.11 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) The Company uses a graded drug cost trend rate which assumes a 5.05 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2020 was completed in 2021 for the registered defined benefit pension plans. The estimated contribution for 2022 is $3.0 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2023.

13. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2021	2020
Trade accounts receivable and contract assets	**129,632**	133,802
Other accounts receivable	**14,642**	1,736
	144,274	135,538

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2021	2020
Trade accounts receivable from parent and affiliate companies	**2,276**	3,751
Other accounts receivable from parent and affiliate companies	**1,030**	1,340
	3,306	5,091

The significant changes in trade accounts receivable and contract assets are as follows:

December 31, 2019	137,599
Revenue from satisfied performance obligations	1,160,576
Credit loss allowance	(945)
Payments received	(1,163,428)
December 31, 2020	133,802
Revenue from satisfied performance obligations	**1,179,638**
Payments received	**(1,183,808)**
December 31, 2021	**129,632**

CUSTOMER CONTRIBUTIONS AND OTHER DEFERRED REVENUES

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Customer contributions and other deferred revenues at December 31 are as follows:

	2021	2020
Customer contributions	**1,040,262**	975,195
Other deferred revenues	**6,347**	5,679
	1,046,609	980,874

Changes in customer contributions balance are summarized below.

December 31, 2019	978,467
Receipt of customer contributions	29,064
Amortization	(32,336)
December 31, 2020	975,195
Receipt of customer contributions	**95,597**
Amortization	**(30,530)**
December 31, 2021	**1,040,262**

14. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2021		2020
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**2,440,000**	**61,000**	2,440,000	61,000
2.292% Series 4	**1,560,000**	**39,000**	1,560,000	39,000
Issuance costs		**(1,720)**		(1,720)
		98,280		98,280

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.14325	1.36 %	June 1, 2026 (4)	Series 5 (5)

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

	2021		2020	
Issued	Shares	Amount	Shares	Amount
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	–	–	1,748,578	43,714
Issuance costs		–		(44)
		–		43,670

In 2021, the Company redeemed all of the issued 4.60 per cent Series V Preferred Shares for $44 million plus accrued dividends.

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of the Company at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2021	2020
Cumulative Redeemable Preferred Shares		
4.60% Series 1	**1.1500**	1.1500
2.292% Series 4 (1)	**0.5669**	0.5608
Perpetual Cumulative Second Preferred Shares		
4.60% Series V (2)	**0.7456**	1.1500

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.243 per cent.

(2) The 4.60% Series V Preferred Shares were redeemed on August 27, 2021.

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 20, 2022, the Company declared first quarter eligible dividends of $0.28750 per Series 1 Preferred Share and $0.14325 per Series 4 Preferred Share.

15. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2021 and 2020	**23,598,608**	**743,698**	**14,463,663**	**468,730**	**38,062,271**	**1,212,428**

Class A and B shares have no par value.

The Company declared and paid cash dividends of $7.94 per Class A non-voting share and Class B common share during 2021 (2020 - $8.25). The payment and amount of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On February 18, 2022, ATCO Electric declared a first quarter dividend of $1.87 per Class A and Class B share.

16. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities for the year ended December 31 are summarized below.

	2021	2020
Depreciation and amortization	**311,608**	298,731
Income tax expense	**65,048**	73,093
Contributions by customers for extensions to plant	**95,597**	29,064
Amortization of customer contributions	**(30,530)**	(32,336)
Net finance costs	**227,274**	224,223
Income taxes paid	**(2,221)**	(1,483)
Provision on early termination of the master service agreement for managed IT services *(Note 3)*	**–**	28,002
Other	**(16,530)**	(12,556)
	650,246	606,738

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital for the year ended December 31 are summarized below.

	2021	2020
Operating activities		
Accounts receivable and contract assets	**4,479**	7,692
Accounts receivable from parent and affiliate companies	**1,475**	1,575
Inventories	**366**	(276)
Prepaid expenses and other current assets	**57**	105
Accounts payable and accrued liabilities	**7,651**	(8,275)
Accounts payable to parent and affiliate companies	**14,212**	(9,604)
Provisions and other current liabilities	**31,139**	614
	59,379	(8,169)
Investing activities		
Accounts receivable and contract assets	**(13,215)**	(4,057)
Accounts receivable from parent and affiliate companies	**345**	(478)
Accounts payable and accrued liabilities	**(6,660)**	(10,297)
	(19,530)	(14,832)

CASH POSITION

Cash position at December 31 is comprised of:

	2021	2020
Cash	**15,467**	4,854
Short-term advances to parent and affiliate companies *(Note 23)*	**2,999**	29,000
Cash and cash equivalents	**18,466**	33,854
Bank indebtedness	**(3,021)**	–
Short-term advances from parent and affiliate companies *(Note 23)*	**(54,700)**	(109,000)
	(39,255)	(75,146)

17. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash, short-term advances to parent company, accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent and affiliated companies, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company's financial instruments measured at amortized cost are as follows:

			2021		2020
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Liabilities					
Long-term debt	11	**5,056,273**	**6,100,162**	4,996,922	6,490,818

OFFSETTING FINANCIAL ASSETS

At December 31, the following financial assets are subject to offsetting, enforceable master netting arrangements and similar agreements:

			2021			2020
Financial Assets	Gross Amount	Gross Amount Offset	Net Amount Recognized	Gross Amount	Gross Amount Offset	Net Amount Recognized
Accounts receivable and contract assets	**64,733**	**(38,734)**	**25,999**	60,541	(38,674)	21,867

18. RISK MANAGEMENT

The Company is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to the share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparties inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents and accounts receivable and contract assets and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the non-consolidated balance sheet.

The company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

The majority of the Company's accounts receivable and contract assets credit risk is reduced by financial security provided by Direct Energy and by retailers in accordance with provisions contained within the Electric Utilities Act Distribution Tariff Regulation A.R. 162/2003, and the Company's ability under the Regulation to recover through its distribution tariff any costs not recovered by a claim against such retailer security. At December 31, 2021, the Company held $105 million in letters of credit for certain counterparty receivables (2020 - $92 million).

Accounts receivable and contract assets are non-interest bearing and are generally due in 30 to 90 days. The credit loss allowance recorded in 2021 was nil and the reversal of prior year's credit write-off was $1.5 million (2020 - $1.3 million and nil). The credit loss allowance balance at December 31, 2021, was $0.4 million (2020 - $0.9 million). At December 31, 2021, the Company had $2.7 million of trade receivables past due greater than 30 days (2020 - $3.9 million). No other impairments have been identified within accounts receivable or contract assets.

The Company has also entered into guarantee arrangements with Direct Energy's parent company (NRG Energy) relating to the retail energy supply functions performed by Direct Energy (see Note 21).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Lines of credit

At December 31, 2021, the Company has a line of credit of $10.0 million (2020 - $10.0 million). The credit line enables the Company to obtain financing for general business purposes. At December 31, 2021, $10.0 million of the credit line was available (2020 - $10.0 million).

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities, of the Company's financial liabilities at December 31, 2021 based on the contractual undiscounted cash flows.

	2022	2023	2024	2025	2026	2027 and thereafter
Bank indebtedness	3,021	–	–	–	–	–
Short-term advances from parent and affiliated companies	54,700	–	–	–	–	–
Accounts payable and accrued liabilities	101,003	–	–	–	–	–
Accounts payable to parent and affiliate companies	72,670	–	–	–	–	–
Long-term debt:						
Principal	50,010	30,404	116,000	–	–	4,887,100
Interest expense	225,487	222,270	212,640	211,323	211,323	4,104,002
	506,891	252,674	328,640	211,323	211,323	8,991,102

The table below analyzes the remaining contractual maturities, of the Company's financial liabilities at December 31, 2020 based on the contractual undiscounted cash flows.

	2021	2022	2023	2024	2025	2026 and thereafter
Short-term advances from parent and affiliated companies	109,000	–	–	–	–	–
Accounts payable and accrued liabilities	100,020	–	–	–	–	–
Accounts payable to parent and affiliate companies	57,340	–	–	–	–	–
Long-term debt:						
Principal	101,000	56,280	23,534	116,000	–	4,727,099
Interest expense	218,388	215,105	212,312	205,673	204,370	3,088,023
	585,748	271,385	235,846	321,673	204,370	7,815,122

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact the Company. This includes causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company’s operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company’s business.

While the Company’s investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on the Company remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across the Company. As a result of these efforts and the Company’s experience in crisis response, the Company’s operations, financial position and performance have not been significantly impacted for the year ended December 31, 2021.

CLIMATE CHANGE RISK

The Company manages climate risks related to assets, including preparing for, and responding to, extreme weather events through activities such as proactive route and site selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital expenditures or acquiring assets, The Company considers site specific climate and weather factors, such as flood plain mapping and extreme weather history.

The Company also continues to explore and implement opportunities in energy efficiency. This process is associated with risks and uncertainties, and is highly dependent on changes in legislation, market price volatility, local and global demand on energy, as well as the timing of when the local and global markets transition to a more energy efficient and cleaner fuels-based economy. The extent and significance of the future impact of such risks and uncertainties remain unknown.

19. CAPITAL DISCLOSURES

The Company's objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for the Company. In October 2020, the Company received the 2021 generic cost of capital decision. The decision established the equity ratio for 2021 at 37.0 per cent for transmission and distribution operations. The capitalization involves the use of long term debt and preferred share financings.

The Company includes share owner's equity, preferred shares, and-long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 3 and 24), in its determination of capitalization. In maintaining or adjusting its capital structure, the Company may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, and long-term debt.

20. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by the AUC. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Leases

The Company evaluates contract terms and conditions to determine whether they contain or are leases. Where a lease exists, the Company determines whether substantially all of the significant risks and rewards of ownership are transferred to the customer, in which case it is accounted for as a finance lease, or remain with the Company, in which case it is accounted for as an operating lease.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management’s best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of electricity. The estimate is derived from unbilled electricity distribution services supplied to customers and is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 18.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, ATCO Electric identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 12.

Asset retirement obligations

ATCO Electric estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

Use of judgments and estimates around the COVID-19 pandemic

For the year ended December 31, 2021, the Company performed an assessment of the impacts of uncertainties around the COVID-19 pandemic on its non-consolidated financial position, financial performance and cash flows. The assessment required use of judgments and estimates and resulted in no material impacts to the non-consolidated financial statements.

21. CONTINGENCIES

AUC enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether the Company failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and the Company are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $43 million ($41.1 million after-tax) related to the proceeding.

Measurement inaccuracies

Measurement inaccuracies occur from time to time on electricity and gas metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

Direct Energy Partnership retail obligation

In 2004, ATCO Gas and ATCO Electric Distribution transferred their retail energy supply businesses to Direct Energy Partnership (Direct Energy). The legal obligations of ATCO Gas and ATCO Electric Distribution for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric Distribution, with no refund of the transfer proceeds to Direct Energy.

NRG Energy Inc. (NRG), Direct Energy's parent company, provided a $300 million guarantee, supported by a $300 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric Distribution under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

Other

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the non-consolidated financial statements.

22. COMMITMENTS

In addition to commitments disclosed elsewhere in the non-consolidated financial statements, the Company has entered into a number of operating leases for office premises and equipment and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter
Purchase obligations:						
Operating and maintenance agreements	28,015	12,125	11,529	3,839	–	–
Capital expenditures	181,061	–	–	–	–	–
	209,076	12,125	11,529	3,839	–	–

23. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Electric entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2021	2020
CU Inc. / Canadian Utilities Limited / ATCO Ltd.	Parent	Contract Services	Revenue	**82**	–
		Administration, financial management, aircraft and rent	Other expenses	**49,604**	47,303
		Aircraft, rent and leasehold improvements	Property, plant and equipment	**13,517**	15,930
		Licensing fees	Other expenses	**6,428**	5,155
		Interest income	Interest income	**148**	428
		Long-term and short-term interest expense and guarantee fees	Interest expense	**229,845**	232,179
Northland Utilities Enterprises Ltd.	Subsidiary	Administration, financial management, engineering services, materials management and metering services	Revenues	**1,811**	1,342
		Long-term and short-term interest income	Interest income	**1,511**	1,520
ATCO Electric Yukon	Subsidiary	Administration, financial management, materials management and metering services	Revenues	**892**	769
		Long-term and short-term interest income	Interest income	**3,241**	3,264
		Short-term interest expense	Interest expense	**14**	21
ATCO Structures & Logistics	Affiliate	Administration and camp services	Other expenses	**13**	39
		Trailer supply and noise management services and purchase of	Property, plant and equipment	**40**	–
		Project Services	Revenues	**–**	63
ATCO Gas	Affiliate	Administration and rent	Revenues	**329**	348
		Contract services	Revenues	**1,501**	1,092
		Administration, rent, joint trenching, electronics and instrumentation testing and purchase of	Other expenses	**–**	341
		Contract services	Other expenses	**134**	–
		Contract services	Property, plant and equipment	**1,206**	979

Entity	Relationship	Transaction	Recorded As	2021	2020
ATCO Power	Affiliate	Transfer of assets	Property, plant and equipment	–	–
ASHCOR	Affiliate	Contract services	Revenues	–	84
ATCO Power (2010) Ltd.	Affiliate	Contract services	Revenues	**7,871**	13,759
ATCO Energy Solutions Ltd.	Affiliate	Operate and maintain facilities, project services, communication services and administration	Revenues	**327**	192
ATCO Investments Ltd.	Affiliate	Contract services	Revenues	**124**	108
		Rent	Rent, parking and utilities	**780**	824
ATCO Land Holdings	Affiliate	Contract services	Revenues	**2**	–
ATCO Frontec	Affiliate	Contract services	Property, plant and equipment	**49**	–
ATCO Pipelines	Affiliate	Contract services	Revenues	**317**	87
ATCO Energy Ltd.	Affiliate	Billing and call centre services	Revenues	**45**	53
		Retail service revenue	Revenues	**66,310**	56,341
		Distribution service costs	Other expenses	**1,008**	843
		Contract services	Other expenses	–	2
		Contract services	Property, plant and equipment	**5**	–
ATCO Infrastructure Solutions Ltd.	Affiliate	Contract services	Revenues	**6,253**	3,729
2200427 Alberta Ltd.	Affiliate	Financial & Administrative services	Revenues	–	3

Affiliate companies are subsidiaries of ATCO Electric's parent or ultimate parent.

ATCO Electric incurred $0.5 million (2020 - $0.3 million) in advertising and promotion expenses from an entity related through common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2021	2020
Receivables from related parties [1]	Accounts receivable from parent and affiliate companies	**3,306**	5,091
Payables to related parties [1]	Accounts payable to parent company and affiliate companies	**72,670**	57,340
Short-term advances [2]	Short-term advances to parent company	**2,999**	29,000
	Short-term advances from parent and affiliate companies	**54,700**	109,000
Long-term advances *(Note 11)*	Long-term debt to parent company	**5,056,273**	4,996,922
Equity preferred shares *(Note 14)*	Equity preferred shares to parent company	**98,280**	141,968

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

Long-term advances to subsidiary companies

Long-term advances to subsidiary companies are shown in the table below.

	Effective Interest Rate	2021	2020
Yukon Electric			
Debentures - unsecured [1]	4.535% (2020 - 4.535%)	**70,800**	70,800
Northland Utilities Yellowknife			
Debentures - unsecured [1]	4.789% (2020 - 4.815%)	**24,063**	24,063
Northland Utilities NWT			
Debentures - unsecured [1]	3.850% (2020 - 3.850%)	**9,160**	9,160
		104,023	104,023

(1) Interest is the average effective interest rate weighted by principal amounts outstanding. The debentures mature between May 2023 and November 2052. Long-term advances are unsecured and will be settled in cash. No provisions are held against the advances.

24. ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

The Company is regulated by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, and service area.

Distribution Operations

The distribution operations of the Company are under a form of rate regulation called Performance Based Regulation (PBR). The current PBR period applies for a period of five years from 2018 to 2023. PBR allows distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five year period.

Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow the Company to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control, that are material, should not have significantly influenced the I Factor, are prudently incurred, are recurring and could vary greatly from year to year (Y Factor) or are unforeseen and unlikely to recur (Z Factor).

Transmission Operations

The transmission operations of the Company are subject to a cost of service regulation under which the AUC establishes the revenues required to: (1) recover forecast operating costs of providing the regulated service, including depreciation and amortization and income taxes, and (2) provide a fair and reasonable return on utility investment, or rate base. Since actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the investment in property, plant and equipment and intangible assets approved by the AUC. The investment includes an allowance for working capital and is reduced by accumulated depreciation and amortization, reserves for future removal and site restoration costs, and unamortized contributions by utility customers for plant extensions. These operations earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base which is based on the historical and forecast weighted average cost of debt and preferred shares. The AUC also establishes the capital structure.

The transmission operations of the Company seek approval for their revenue requirement either by submitting a general tariff application to the AUC or negotiating settlement with interested parties. In the latter case, the AUC monitors the negotiated settlement process and approves any agreement. The AUC may approve interim rates or the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Electricity transmission

Revenue from electricity transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity distribution

Revenue from distribution of electricity is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity is based on tariff-approved rates established by the Alberta Electric Systems Operator and rates stipulated in contracts respectively. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission and distribution prices. The recovery is part of the provision of continuous electricity transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. The tax effect of temporary differences from investments in subsidiaries are not accounted for where the Company is able to control the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

Current income tax assets and liabilities are offset where the Company has the legally enforceable right to offset and the Company intends to either settle on a net basis or realize the asset and settle the liability simultaneously.

Deferred income tax assets and liabilities are offset where the Company has a legally enforceable right to set off tax assets and liabilities, and when the deferred income tax assets and liabilities relate to income taxes levied by the same tax authority.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

INVESTMENTS

The Company’s investment in subsidiary companies is initially recognized at cost and only dividends received are taken into earnings. The exemption from applying the consolidation method has been used.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset’s carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	25 to 67 years	51 years	1.9 %
Electricity distribution equipment	15 to 55 years	44 years	2.3 %
Buildings	45 to 50 years	40 years	2.5 %
Other plant, equipment and machinery	5 to 25 years	19 years	5.3 %

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and 75 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

PROVISIONS

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event;

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the non-consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management’s best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, included in other liabilities, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company’s business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the non-consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

The Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Company is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2019.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. The Company does not have any liability to the Group Plan other than the minimum funding requirements of its subsidiaries. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Company accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, the Company is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the non-consolidated statements of earnings.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2021, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

25. SUBSEQUENT EVENTS

The AUC enforcement branch and ATCO Electric Transmission commenced settlement discussions in January 2022. On March 18, 2022, the AUC enforcement branch and ATCO Electric Transmission concluded discussions and notified the AUC that the parties had reached a settlement on all matters. On April 14, 2022, the settlement was filed with the AUC, reflecting an agreed administrative penalty of $31 million, the removal of $11 million in project costs from rate base, and the implementation of revised practices and policies. The AUC is currently determining the next process steps.

ATCO Electric Transmission (AET)
SUMMARY OF REVENUE REQUIREMENT
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Return on Rate Base	Sch 2.0-T	303.2	309.6	(6.4)	-2.1%	
2	Fuel		3.1	3.5	(0.4)	-10.4%	
3	Operating and Maintenance	Sch 3.0-T	156.5	167.7	(11.3)	-6.7%	
4	Depreciation and Amortization	Sch 4.0-T	208.8	210.8	(2.0)	-1.0%	
5	Utility Income Tax	Sch 5.0-T	35.1	33.5	1.7	5.0%	
6	Subtotal		706.7	725.2	(18.4)	-2.5%	
7							
8	Revenue Offsets		(20.3)	(27.2)	6.9	-25.3%	
9							
10	**Total Transmission Revenue Requirement**	Sch 10	686.4	697.9	(11.5)	-1.7%	
11							
12							
13	<u>Detailed Revenue Requirement</u>						
14	Transmission Tariff Revenue*		689.7	698.1	(8.4)	-1.2%	
15	Deferral Account		(3.3)	(0.2)	(3.1)	1566.0%	**Note 1**
16	**Total Transmission Revenue Requirement**	Line 10	686.4	697.9	(11.5)	-1.6%	

17

18 * The 2021 Tariff Revenue is AET's 2021 Tariff as Approved within the 2020-2022 GTA Post Disposition Filing (Exhibit PD-26477-X0011.02).

19

20 **Variance Explanations**

21

22 **Note 1:** 2021 Actuals (refunds) are higher by ($3.1M) due to the annual true up of deferral accounts. The difference is mainly due to higher refunds of the Direct Assign Capital deferral ($2.8M), Capital Repair deferral ($0.7M), and ROW deferral ($0.1M), offset by a lower refund of the Property Tax deferral ($0.5M). Balances accumulated in the deferral account will be applied for in AET's 2021 Transmission Deferral Settlement filed within its 2023-2025 GTA, Proceeding 27062.

23

24

25 **Reference to Approved Forecast**

26

27 Please refer to AET's 2020-2022 GTA Compliance Post Disposition Filing (Exhibit PD-26477-X0011.02) for the Approved forecasts for 2020 and 2021.

ATCO Electric Transmission (AET)
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actuals

Line No.	Description	Cross-Reference	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $	Working Paper Reference
1	Return on Long Term Debt (Farms Irrigation Transmission)				11.7	5.82%	0.7	
2	Return on Equity (Farms, Irrigation Transmission)				20.3	5.82%	1.2	
3	**Mid Year Rate Base (Farms, Irrigation Transmission)**				32.0	5.82%	1.9	
4								
5	**Mid Year Rate Base**							
6	Long-Term Debt	Sch 2.2-T	3,216.5	61.51%	3,063.5	4.56%	139.7	
7	Preferred Shares	Sch 2.2-T	77.7	1.49%	74.0	3.85%	2.9	
8	Common Equity	Sch 2.2-T	1,934.7	37.00%	1,842.7	8.61%	158.7	
9	**Mid-Year Net Rate Base**	Sch 1.0-T	5,229.0	100.00%	4,980.3	6.09%	303.2	
10	Contribution for Extensions				521.4			
11	No Cost Capital	Sch 2.1-T			257.6			
12	**Mid Year Rate Base**				5,759.2			

ATCO Electric Transmission (AET)

SUMMARY OF MID-YEAR RATE BASE

FOR THE YEAR ENDED DECEMBER 31, 2021

($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Gross Utility Plant in Service						
2	Opening Balance	Sch 4.1-T	7,664.3	7,575.4	88.8	1.2%	
3	Closing Balance	Sch 4.1-T	7,759.5	7,678.8	80.6	1.0%	
4	**Mid-Year Gross Utility Plant in Service**		7,711.9	7,627.1	84.7	1.1%	
5							
6	Accumulated Depreciation - Utility						
7	Opening Balance	Sch 4.1-T	1,918.7	1,728.3	190.3	11.0%	
8	Closing Balance	Sch 4.1-T	2,082.5	1,922.0	160.5	8.3%	
9	**Mid-Year Accumulated Depreciation - Utility**		2,000.6	1,825.2	175.4	9.6%	
10							
11	Contributions in Aid of Construction						
12	Opening Balance		529.9	529.7	0.2	0.0%	
13	Closing Balance		516.1	529.9	(13.8)	-2.6%	
14	**Mid-Year Utility Contributions in Aid of Construction**		523.0	529.8	(6.8)	-1.3%	
15							
16	Amortization of Contributions						
17	Opening Balance		67.6	58.0	9.5	16.4%	
18	Closing Balance		64.2	67.6	(3.3)	-5.0%	
19	**Mid-Year Utility Amortization of Contributions**		65.9	62.8	3.1	4.9%	
20							
21							
22	**Mid-Year Net Utility Plant in Service**		5,254.2	5,335.0	(80.8)	-1.5%	
23							
24	Necessary Working Capital		47.9	50.6	(2.7)	-5.2%	
25							
26	No Cost Capital		(257.6)	(229.7)	(27.9)	12.1%	**Note 1**
27							
28	**Mid-Year Net Rate Base**		5,044.5	5,155.9	(111.3)	(0.0)	
29							
30	Mid-Year Contributions CWIP	Sch. 4.2T Contributions	(64.3)	(39.2)	(25.1)	64.1%	
31							
32	**Total Mid-Year Rate Base and CWIP**	Sch. 2.0-T	**4,980.3**	**5,116.7**	(136.4)	-2.7%	
33							
34							
35	**Variance Explanations**						
36							
37	**Note 1**: 2021 Actuals are higher than 2020 Actuals by ($27.9M) mainly due to an increase in the federal future income tax reserve balance.						

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR CAPITAL STRUCTURE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	Current Year-End	Previous Year-End	Actual Mid-Year Capital	Working Paper Reference
1	Long-Term Debt	Sch 2.3	3,200.3	3,232.7	3,216.5	
2	Preferred Shares	Sch 2.4	63.8	91.7	77.7	
3	Common Equity		1,834.5	2,034.9	1,934.7	
4						
5	**Total Mid-Year Invested Capital**		**5,098.6**	**5,359.4**	**5,229.0**	

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. -Parent											
2			Z	12/18/1991	2022	9.9%	29.3	0.4	29.0	10.0%	29.3	2.9	
3			AA	12/8/1992	2023	9.4%	13.8	0.1	13.7	9.4%	13.8	1.3	
4			2004	11/18/2004	2034	5.9%	71.1	0.4	70.6	5.9%	70.8	4.2	
5			2005	11/30/2005	2035	5.2%	56.3	0.4	56.0	5.2%	56.1	2.9	
6			2006	11/20/2006	2036	5.0%	59.3	0.4	58.9	5.1%	59.0	3.0	
7			2007	11/1/2007	2037	5.6%	79.2	0.5	78.7	5.6%	78.9	4.4	
8			2008	5/26/2008	2028	5.6%	29.3	0.2	29.1	5.6%	29.2	1.6	
9			2008	5/26/2008	2038	5.6%	44.0	0.3	43.7	5.6%	43.8	2.5	
10			2009	3/6/2009	2024	6.2%	68.1	0.4	67.6	6.3%	68.0	4.3	
11			2009	3/7/2009	2039	6.5%	85.7	0.6	85.1	6.6%	85.2	5.6	
12			2010	11/10/2010	2050	4.9%	73.3	0.5	72.8	5.0%	72.9	3.6	
13			2011	10/24/2011	2041	4.5%	192.8	1.2	191.6	4.6%	191.9	8.8	
14			2011	10/24/2011	2061	4.6%	77.1	0.5	76.6	4.6%	76.7	3.6	
15			2012	9/10/2012	2042	3.8%	317.3	2.0	315.3	3.8%	315.7	12.1	
16			2012	9/10/2012	2062	3.8%	126.8	0.8	126.0	3.9%	126.0	4.9	
17			2012	11/14/2012	2052	3.9%	161.2	1.0	160.2	3.9%	160.3	6.2	
18			2013	9/9/2013	2043	4.7%	241.0	1.6	239.4	4.8%	239.7	11.4	
19			2013	9/18/2013	2063	4.9%	75.0	0.6	74.4	4.9%	74.4	3.7	
20			2013	11/7/2013	2053	4.6%	225.0	1.4	223.6	4.6%	223.7	10.3	
21			2014	9/5/2014	2044	4.1%	555.0	3.5	551.5	4.1%	552.0	22.8	
22			2014	10/17/2014	2054	4.1%	180.0	1.2	178.8	4.1%	178.9	7.4	
23			2015	7/27/2015	2045	4.0%	110.0	0.8	109.2	4.0%	109.3	4.4	
24			2015	10/29/2015	2055	4.2%	185.0	1.3	183.7	4.3%	183.8	7.8	
25			2018	11/21/2018	2048	4.0%	90.0	0.6	89.4	4.0%	89.4	3.6	
26			2019	9/5/2019	2049	3.0%	72.0	0.5	71.5	3.0%	71.5	2.1	
27											3,200.3	145.5	4.5%
28													
29		Short-term Debt / (Investment)				0.8%	-		-	0.8%	-	-	
30													
31		2021 Ending Balance									3,200.3	145.5	4.5%
32		2021 Opening Balance									3,232.7	148.0	4.6%
33		**Mid-Year Balance**									**3,216.5**	**146.7**	**4.6%**

ATCO Electric Transmission (AET)
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
2		4	2010	2.29%	24.9	-	24.9	0.6	2.29%
3									
4		Current Year-End Balance			63.8	-	63.8	2.4	3.70%
5		Prior Year-End Balance			91.7	-	91.7	3.6	3.96%
6		Total			155.5		155.5	6.0	3.85%
7		Mid-Year Balance			77.7		77.7	3.0	3.85%
8									

9 **Note:**
10 Series V Preferred Shares were redeemed on August 27, 2021.
11 Series 4 Preferred Shares reset in 2021.

ATCO Electric Transmission (AET)

SUMMARY OF OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDED DECEMBER 31, 2021

($Millions)

Line No.	Acct No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1		**Direct Operation & Maintenance Expense**						
2	560	Supervision and Engineering		3.0	3.4	(0.3)	-10.1%	
3	561	Control Centre Operations		4.9	4.8	0.0	1.0%	
4	562	Station Equipment Expenses		8.6	9.1	(0.5)	-5.6%	**Note 1**
5	563/569	Overhead Lines Expenses & Operation Maintenance		2.7	2.7	(0.1)	-2.3%	
6	566	Miscellaneous Transmission Expense		28.7	33.5	(4.8)	-14.3%	**Note 2**
7	567	Right of Way Payments		6.7	6.8	(0.1)	-1.3%	
8	571.1	Vegetation Management		5.2	7.9	(2.7)	-34.2%	**Note 3**
9	575	IT Support		-	-	-	0.0%	**Note 4**
10		Total Direct Operation & Maintenance Expense		59.8	68.3	(8.5)	-12.4%	
11								
12		**Isolated Generation Operation & Maintenance**						
13	537	Hydro Expenses		-	0.0	(0.0)	-100.0%	
14	546	Combustion Engines/Turbine Operations		1.0	1.2	(0.2)	-17.1%	
15	554	Combustion Engines/Turbine Maintenance		0.6	0.7	(0.0)	-4.1%	
16	557	Other Expenses		0.2	0.5	(0.3)	-58.7%	
17		Total Isolated Generation Operation & Maintenance		1.8	2.3	(0.5)	-22.1%	
18								
19		**Administrative and General**						
20	920	General Administration		11.8	12.8	(1.1)	-8.2%	
21	921	Office Supplies and Expenses		5.0	4.6	0.3	7.5%	
22	923	Outside Services Employed		0.5	0.6	(0.1)	-21.5%	
23	924	Insurance Premiums		4.3	3.7	0.6	17.0%	
24	925	Injuries and Damages		0.8	0.8	-	0.0%	
25	928	Board Expenses		1.2	1.2	0.0	0.0%	
26	930.2	Miscellaneous General Expenses		16.1	15.9	0.3	1.6%	
27	931.1	Head Office Rent		1.3	1.4	(0.1)	-5.9%	
28	934	IT G&A Expense		12.8	15.6	(2.8)	-18.1%	**Note 5**
29	941	Board Expenses Disallowed		0.7	1.0	(0.3)	-28.6%	
30	935.2	Maintenance Company Owned Houses		0.2	0.1	0.1	54.9%	
31				54.7	57.8	(3.1)	-5.4%	
32		Non-utility Items		(5.9)	(5.8)	(0.1)	1.5%	
33		Total Administrative and General		48.7	51.9	(3.2)	-6.1%	
34								
35		Taxes Other Than Income		45.4	44.5	0.9	2.1%	
36								
37		Farms, Irrigation Transmission Operating Costs		0.6	0.7	(0.1)	-7.8%	
38								
39		**Total Transmission O&M Costs**	Sch 1.0-T	**156.5**	**167.7**	**(11.3)**	**-6.7%**	

Variance Explanations

Note 1 2020 Actuals have been restated from $9.3 to $9.1 due to the reclassification of IT costs to USA 934.

Note 2 2021 Actuals are lower than 2020 Actuals by ($4.8) mainly due to lower affiliate cost of goods sold for affiliate work ($5.6) and SOP for Alberta PowerLine ($1.4), partially offset by cancelled projects write-offs ($1.6), higher SOP cost of goods sold ($0.3) and labour ($0.2). Affiliate and SOP cost of goods sold are offset by affiliate revenue and have no impact on revenue requirement.

Note 3 2021 Actuals are lower than 2020 Actuals by ($2.7) mainly due to reduction in mechanical and herbicide treatment area resulting from the transition to a full herbicide cycle.

Note 4 2020 Actuals have been restated from $2.8 to nil due to the reclassification of IT costs to USA 934.

Note 5 2021 Actuals are lower than 2020 Actuals by ($2.8) mainly due to lower IT transition costs associated with the realignment of IT services.

ATCO Electric Transmission (AET)
SUMMARY OF DEPRECIATION EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Transmission		194.8	196.8	(2.0)	-1.0%	
2	Amortization of Differences		4.4	4.4	0.0	0.0%	
3	**Subtotal**		199.2	201.2	(2.0)	-1.0%	
4							
5	**Direct General PP&E**						
6	Structures & Improvements		3.1	3.1	(0.0)	-0.7%	
7	Office Furniture and Equipment		0.8	0.8	(0.0)	-1.0%	
8	Computer Equipment		0.5	0.2	0.3	107.3%	
9	Transportation Equipment		3.4	3.1	0.3	10.5%	
10	Tools & Instruments		3.4	3.5	(0.0)	-1.2%	
11	Leasehold Improvements		1.2	1.1	0.0	2.5%	
12	Software		8.4	8.5	(0.1)	-1.0%	
13	Amortization of Differences		0.3	0.3	0.0	0.0%	
14	**Subtotal**		21.1	20.7	0.5	2.2%	
15							
16							
17	**Transmission Gross Provision**		220.3	221.9	(1.5)	-0.7%	
18							
19	Farms, Irrigation Transmission		1.4	1.5	(0.1)	-6.5%	
20							
21	**Total Transmission Gross Depreciation Expense**		221.7	223.3	(1.6)	-0.7%	
22							
23							
24	Gross Depreciation Expense		221.7	223.3	(1.6)	-0.7%	
25	Vehicle Depreciation Capitalized		(2.3)	(2.0)	(0.3)	15.5%	
26	Amortization of Contributions		(10.7)	(10.6)	(0.1)	0.8%	
27	**Total Depreciation and Amortization Expense**		208.8	210.8	(2.0)	-1.0%	
28							
29							
30	**Total Depreciation and Amortization Expense**	Sch 1.0-T	208.8	210.8	(2.0)	-1.0%	

ATCO Electric Transmission (AET)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Prior years' Disallowances	Prior Year Disallowances & Opening Balance Adjustments	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	2021 Pension Disallowance	Balance at 12/31/2021
1	Transmission		7,358.4	(14.6)	7,343.8	129.3	(39.5)	-	0.4	(0.1)	7,433.9
2											
3	**Direct General PP&E**										
4	Land		4.8	-	4.8	-	-	-	(0.0)	-	4.8
5	Structures and Improvements		121.5	(0.0)	121.5	0.7	(0.5)	-	(0.0)	-	121.7
6	Office Furniture and Equipment		12.6	-	12.6	0.1	(0.2)	-	-	-	12.6
7	Computer Equipment		1.9	-	1.9	1.7	(0.3)	-	-	-	3.3
8	Transportation Equipment		57.5	-	57.5	5.1	(3.1)	(0.1)	-	-	59.4
9	Tools and Instruments		34.0	-	34.0	2.2	(1.7)	-	-	-	34.5
10	Leasehold Improvements		11.6	-	11.6	0.2	0.1	-	-	-	11.8
11	Software		76.5	-	76.5	2.9	(2.0)	-	-	-	77.4
12	**Subtotal**		320.5	(0.0)	320.5	12.9	(7.7)	(0.1)	(0.0)	-	325.6
13											
14	**Subtotal - Utility Plant in Service**	Sch 2.1-T	7,678.8	(14.6)	7,664.3	142.2	(47.2)	(0.1)	0.4	(0.1)	7,759.5
15											
16	Capital Work in Progress (CWIP)		152.2	-	152.2	17.4	-	-	-	-	169.6
17											
18	**Total Transmission**		7,831.0	(14.6)	7,816.5	159.6	(47.2)	(0.1)	0.4	(0.1)	7,929.1
19											
20											

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Disallowances	Prior Year Disallowances & Opening Balance Adjustments	Depreciation Provision	2021 Retirements	2021 Transfers	2021 Adjustments	2021 Net Salvage	Balance at 12/31/2021
21	Transmission		1,799.2	(3.3)	1,795.9	199.2	(39.5)	-	(1.7)	(7.9)	1,945.9
22											
23	**Direct General PP&E**										
24	Land		0.0	-	0.0	-	-	-	-	-	0.0
25	Structures and Improvements		27.7	(0.0)	27.7	3.2	(0.5)	-	(0.0)	(0.1)	30.4
26	Office Furniture and Equipment		6.9	-	6.9	0.8	(0.2)	-	-	-	7.5
27	Computer Equipment		0.6	-	0.6	0.5	(0.3)	-	-	-	0.8
28	Transportation Equipment		26.4	-	26.4	3.2	(3.1)	(0.1)	-	0.7	27.1
29	Tools and Instruments		16.9	-	16.9	3.6	(1.7)	-	-	-	18.8
30	Housing		0.5	-	0.5	-	-	-	-	-	0.5
31	Leasehold Improvements		3.3	-	3.3	1.4	0.1	-	-	(0.0)	4.7
32	Software		40.4	-	40.4	8.4	(2.0)	-	(0.2)	-	46.6
33	**Subtotal**		122.8	(0.0)	122.8	21.1	(7.7)	(0.1)	(0.2)	0.6	136.6
34											
35	**Total Transmission**	Sch 2.1-T	1,922.0	(3.3)	1,918.7	220.3	(47.2)	(0.1)	(1.9)	(7.3)	2,082.5
36											
37											
38											
39	**Note:** AFUDC is a component of all categories and is therefore not disclosed separately in this continuity schedule.										

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual CWIP Balance	2021 Actual Cap Expend	2021 Actual Cap Adds	2021 Actual CWIP Balance	2020 Actual CWIP Balance	2020 Actual Cap Expend	2020 Actual Cap Adds	2020 Actual CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
1		**CAPITAL MAINTENANCE**												
2		Transmission Capital Maintenance - Substations	17.3	31.4	33.2	15.5	20.2	25.1	28.0	17.3	6.3	25.1%	5.2	18.6%
3		Transmission Capital Maintenance - Lines	11.0	16.2	24.1	3.1	3.1	31.3	23.4	11.0	(15.1)	-48.2%	0.7	3.0%
4		Transmission System Right-of-Way	0.1	2.3	2.3	0.1	-	2.1	2.0	0.1	0.2	9.5%	0.3	15.0%
5		Transmission Rights-of-Way Widening	0.5	4.8	4.5	0.8	-	4.9	4.4	0.5	(0.1)	-2.0%	0.1	2.3%
6		Substation Rebuilds	3.1	12.5	5.0	10.6	0.9	6.4	4.2	3.1	6.1	95.3%	0.8	19.0%
7		Transmission Line Ground Clearance	4.4	4.8	5.5	3.7	1.0	5.6	2.2	4.4	(0.8)	-14.3%	3.3	100.0%
8		Transmission Line Rebuilds (Partial & Complete)	13.5	8.3	-	21.8	7.9	5.6	-	13.5	2.7	48.2%	-	0.0%
9		Kearl 9L101	18.9	5.1	24.0	-	2.6	16.3	-	18.9	(11.2)	-68.7%	24.0	100.0%
10		Transmission Double Circuit	0.1	-	0.1	-	0.4	(0.2)	0.1	0.1	0.2	-100.0%	-	0.0%
11		ATCO 9L32/66 Line Move	0.4	2.7	-	3.1	0.1	0.3	-	0.4	2.4	100.0%	-	0.0%
12		Temporary Line Relocation- 9L66/9L92 (Phase 2 Joslyn - Muskeg)	0.6	0.3	-	0.9	0.4	0.2	-	0.6	0.1	50.0%	-	0.0%
13		Youngstown Substation Purchase	0.1	0.2	-	0.3	0.1	-	-	0.1	0.2	100.0%	-	0.0%
14			70.0	88.6	98.7	59.9	36.7	97.6	64.3	70.0	(9.0)	-9.2%	34.4	53.5%
15		**TELECOMMUNICATION**												
16		Telecommunication Capital Maintenance	4.5	5.4	8.8	1.1	1.7	7.0	4.2	4.5	(1.6)	-22.9%	4.6	100.0%
17		Mobile Communication System	-	-	-	-	0.3	(0.3)	-	-	0.3	-100.0%	-	0.0%
18		Network Multiplexor Upgrade	-	0.2	0.2	-	0.2	0.7	0.9	-	(0.5)	-71.4%	(0.7)	-77.8%
19		Telecom Tower Replacements	0.4	1.8	2.1	0.1	0.1	0.6	0.3	0.4	1.2	100.0%	1.8	100.0%
20		Telecom Building Replacements/Refurbishments	-	0.2	0.0	0.2	0.1	-	0.1	-	0.2	100.0%	(0.1)	-79.0%
21		Replacement of End of Life Radios	2.0	3.7	3.3	2.4	3.0	4.5	5.5	2.0	(0.8)	-17.8%	(2.2)	-40.0%
22		Telecom Capacity & Reliability Upgrade Projects	0.9	1.3	1.1	1.1	0.5	1.6	1.2	0.9	(0.3)	-18.8%	(0.1)	-8.3%
23		Mobile Radio Expansion	0.4	0.1	0.5	-	0.8	0.3	0.7	0.4	(0.2)	-66.7%	(0.2)	-28.6%
24		Various Other Projects Below $0.0 individually - Telecom	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
25			8.2	12.7	16.0	4.9	6.7	14.4	12.9	8.2	(1.7)	-11.8%	3.1	24.2%
26		**SCADA / EMS**												
27		Operational Information Systems	0.5	1.1	1.6	-	0.3	0.8	0.6	0.5	0.3	37.5%	1.0	100.0%
28		Regulatory Compliance & Security Programs	1.0	1.0	0.3	1.7	1.2	1.6	1.8	1.0	(0.6)	-37.5%	(1.5)	-83.3%
29			1.5	2.1	1.9	1.7	1.5	2.4	2.4	1.5	(0.3)	100.0%	(0.5)	-20.8%
30														
31		**TRANSMISSION ISOLATED GENERATION**												
32		Install Alternate Power Supply/Renewables	12.5	9.2	19.5	2.2	3.9	12.9	4.3	12.5	(3.7)	-28.7%	15.2	100.0%
33		Rebuild Jasper Palisades Substation	0.3	-	0.2	0.1	0.3	-	-	0.3	-	0.0%	0.2	100.0%
34		Refurbish/Replace Engines and Turbines	0.7	0.5	1.0	0.2	1.0	1.0	1.3	0.7	(0.5)	-50.0%	(0.3)	-23.1%
35		Transmission Isolated Operations Capital Maintenance	0.4	1.7	-	2.1	0.4	1.3	1.3	0.4	0.4	30.8%	(1.3)	-100.0%
36			13.9	11.4	20.7	4.6	5.6	15.2	6.9	13.9	(3.8)	-25.0%	13.8	100.0%
37														

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual CWIP Balance	2021 Actual Cap Expend	2021 Actual Cap Adds	2021 Actual CWIP Balance	2020 Actual CWIP Balance	2020 Actual Cap Expend	2020 Actual Cap Adds	2020 Actual CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
38		**NORTH WEST FIRE 2019**	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
39														
40		**TOTAL CAPITAL MAINTENANCE**	93.6	114.8	137.3	71.1	50.5	129.6	86.5	93.6	(14.8)	-11.4%	50.8	58.8%
41														
42		**DIRECT ASSIGNED PROJECTS SYSTEM**												
43	53043	Rycroft Transmission Reinforcement	1.7	5.7	-	7.4	1.2	0.5	-	1.7	5.2	100.0%	-	0.0%
44	53320	High Prairie to Triangle 144 kV Line Upgrade	-	(0.2)	(0.2)	-	-	-	-	-	(0.2)	-100.0%	(0.2)	-100.0%
45	53594	Grande Prairie Transmission Reinforcement	0.2	-	-	0.2	0.2	-	-	0.2	-	0.0%	-	0.0%
46	54904	Jasper Transmission Interconnection	-	(2.8)	(2.8)	-	-	6.3	6.3	-	(9.1)	-100.0%	(9.1)	-100.0%
47	54906	Jasper Palisade (781S) Substation Decommissioning	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
48	55145	ATCO 9L32/66	0.1	4.2	-	4.3	-	0.1	-	0.1	4.1	100.0%	-	0.0%
49	55737	Thickwood Development	-	0.6	0.6	-	-	5.8	5.8	-	(5.2)	-89.7%	(5.2)	-89.7%
50	55900	P7071 and P7072 Voice and Data Upgrades	-	0.2	-	0.2	-	-	-	-	0.2	100.0%	-	0.0%
51	56772	Nevis Transformer	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
52	57157	St. Paul Substation & Line	-	0.1	0.1	-	-	-	-	-	0.1	100.0%	0.1	100.0%
53	57159	PENVTD	3.0	2.2	-	5.2	1.1	1.9	-	3.0	0.3	15.8%	-	0.0%
54	57180	57180 Time Domain Line Protection	-	0.4	0.4	-	-	-	-	-	0.4	100.0%	0.4	100.0%
55	58001	Edmonton-Calgary 500 kV East Route	-	-	-	-	-	0.4	0.4	-	(0.4)	-100.0%	(0.4)	-100.0%
56	58112	Central East Transfer Out	3.5	2.9	-	6.4	1.9	1.6	-	3.5	1.3	81.3%	-	0.0%
57	58005	Relocate / Reterminate 7L98 to Lanfine	-	-	-	-	-	0.1	0.1	-	(0.1)	-100.0%	(0.1)	-100.0%
58		Various Other Projects below $0.0 individually	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
59		**TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM**	8.5	13.3	(1.9)	23.7	4.5	16.6	12.6	8.5	(3.3)	-19.9%	(14.5)	-100.0%
60														
61		**DIRECT ASSIGNED PROJECTS - CUSTOMER**												
62	51090	Rainbow Lake Gas	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
63	51162	Blumenort - Windy Hills 144kV Transmission Line	-	-	-	-	1.5	(1.5)	-	-	1.5	-100.0%	-	0.0%
64	51440	Whitetail Peaking Station Interconnection	1.5	0.1	-	1.6	1.5	-	-	1.5	0.1	100.0%	-	0.0%
65	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
66	53034	Ksituan River 754S Capacity Upgrade	-	0.1	0.1	-	-	0.1	0.1	-	-	0.0%	-	0.0%
67	53441	Thornton DTS Increase	0.1	-	-	0.1	-	0.1	-	0.1	(0.1)	-100.0%	-	0.0%
68	53455	M.D. Greenview Load	3.2	0.9	-	4.1	0.8	2.4	-	3.2	(1.5)	-62.5%	-	0.0%
69	53475	ATCO Woodlands Area Load	-	-	-	-	0.2	(0.2)	-	-	0.2	-100.0%	-	0.0%
70	53593	Grande Prairie	7.7	0.5	-	8.2	6.9	0.8	-	7.7	(0.3)	-37.5%	-	0.0%
71	54951	HR Milner 1 & 2 Gas	-	1.0	1.0	-					1.0	100.0%	1.0	100.0%
72	55119	Generator Capacity Increase	3.6	26.8	-	30.4	1.0	2.6	-	3.6	24.2	100.0%	-	0.0%
73	55605	Line Tap	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
74	55753	Merritt Sub and Line	-	-	-	-	0.3	(0.3)	-	-	0.3	-100.0%	-	0.0%
75	56727	Cold Lake Area Cogen	0.2	0.3	-	0.5	0.2	-	-	0.2	0.3	100.0%	-	0.0%
76	56778	Midstream New POD	0.4	-	-	0.4	-	0.4	-	0.4	(0.4)	-100.0%	-	0.0%
77	56779	Wolf Midstream	-	0.3	-	0.3					0.3	100.0%	-	0.0%
78	56810	Grizzly Bear Wind Facility Connection	2.8	2.0	-	4.8	2.3	0.5	-	2.8	1.5	100.0%	-	0.0%
79	56815	Paintearth Wind Project	0.9	0.1	-	1.0	0.8	0.1	-	0.9	-	0.0%	-	0.0%
80	56820	Halkirk II Wind Power Facility	-	-	-	-	0.5	(0.5)	-	-	0.5	-100.0%	-	0.0%
81	56831	RESC Big Sky MPC Solar	-	0.1	-	0.1					0.1	100.0%	-	0.0%
82	56865	Wainwright	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
83	56893	Foster Creek decommissioning	-	0.1	-	0.1					0.1	100.0%	-	0.0%
84	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.3	0.1	-	0.4	(0.1)	-100.0%	-	0.0%
85	58215	Sharp Hills Windfarm	5.3	0.8	-	6.1	4.8	0.5	-	5.3	0.3	60.0%	-	0.0%
86	58225	Garden Plain Wind	0.4	0.5	-	0.9	0.3	0.1	-	0.4	0.4	100.0%	-	0.0%
87	58515	Joss Jenner WAGF - Phase 2	-	0.1	-	0.1					0.1	100.0%	-	0.0%
88	58526	Oyen Wind Power Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
89	58564	BER Hand Hills MPC Wind	0.1	0.2	-	0.3	-	0.1	-	0.1	0.1	100.0%	-	0.0%
90	58562	Hand Hills Wind Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
91	58574	Forestberg Area Solar	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
92	58578	Hand Hills WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
93	58843	Wheatland Wind New POS	0.6	0.4	-	1.0	0.5	0.1	-	0.6	0.3	100.0%	-	0.0%
94	58844	Echo Wind Power New POS	0.9	2.4	-	3.3	0.5	0.4	-	0.9	2.0	100.0%	-	0.0%
95	58922	Eyre 558S Substation Interconnection	0.4	(0.4)	-	(0.0)	0.3	0.1	-	0.4	(0.5)	-100.0%	-	0.0%
96	58923	Currant Lake Substation	6.4	(6.4)	-	-	4.7	1.7	-	6.4	(8.1)	-100.0%	-	0.0%
97	58924	Armitage Substation	7.2	(7.2)	-	-	5.5	1.7	-	7.2	(8.9)	-100.0%	-	0.0%
98	58925	Cavendish Substation	-	0.2	0.2	-	6.2	4.7	10.9	-	(4.5)	-95.7%	(10.7)	-98.2%
99	58965	Heartland Pump Station	0.7	(0.7)	-	-	0.5	0.2	-	0.7	(0.9)	-100.0%	-	0.0%
100		Various Other Projects below $0.0 individually	-	-	-	-	0.3	-	0.3	-	-	0.0%	(0.3)	-100.0%
101		**TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER**	43.2	22.1	1.3	64.0	40.5	14.0	11.3	43.2	8.1	57.9%	(10.0)	-88.5%
102														
103														
104		**TOTAL DIRECT ASSIGNED**	51.7	35.4	(0.6)	87.7	45.0	30.6	23.9	51.7	4.8	15.7%	(24.5)	-100.0%
105														
106		Total Transmission	145.3	150.2	136.7	158.8	95.5	160.2	110.4	145.3	(10.0)	-6.2%	26.3	23.8%
107														

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual CWIP Balance	2021 Actual Cap Expend	2021 Actual Cap Adds	2021 Actual CWIP Balance	2020 Actual CWIP Balance	2020 Actual Cap Expend	2020 Actual Cap Adds	2020 Actual CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
108		**DIRECT GENERAL PP&E**												
109		Tools and Instruments	0.3	2.9	2.6	0.6	0.5	1.7	1.9	0.3	1.2	70.6%	0.7	36.8%
110		Transmission Asset Mgmt. Program	-	0.1	0.1	-	-	0.4	0.4	-	(0.3)	-75.0%	(0.3)	-75.0%
111		Transportation Equipment	3.2	4.4	4.6	3.0	3.8	5.4	6.0	3.2	(1.0)	-18.5%	(1.4)	-23.3%
112			3.5	7.4	7.3	3.6	4.3	7.5	8.3	3.5	(0.1)	-1.3%	(1.0)	-12.0%
113														
114		**SOFTWARE**	3.3	8.1	4.5	6.9	7.4	8.2	12.3	3.3	(0.1)	-1.2%	(7.8)	-63.4%
115			3.3	8.1	4.5	6.9	7.4	8.2	12.3	3.3	(0.1)	-1.2%	(7.8)	-63.4%
116		**BUILDINGS**												
117		Land, Buildings and Structures	0.1	1.2	1.0	0.3	0.5	0.4	0.8	0.1	0.8	100.0%	0.2	25.0%
118			0.1	1.2	1.0	0.3	0.5	0.4	0.8	0.1	0.8	100.0%	0.2	25.0%
119														
120			6.9	16.7	12.8	10.8	12.2	16.1	21.4	6.9	0.6	3.7%	(8.6)	-40.2%
121														
122		IT Common Matters Disallowance	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
123														
124		**Total Transmission Capital Additions**	152.2	166.9	149.5	169.6	107.7	176.3	131.8	152.2	(9.4)	-5.3%	17.7	13.4%
125		Net Salvage			(7.3)				(7.6)					
126		Additions to Property			142.2				124.2					

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL CONTRIBUTIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
1	**DIRECT ASSIGNED PROJECTS**													
2	51074	Fort Nelson Remedial Action Scheme	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
3	51090	ATCO Power Rainbow Lake Gas	0.2	(0.2)	-	-	0.2	-	-	0.2	(0.2)	-100.0%	-	0.0%
4	51162	Blumenort - Windy Hill 144 kV Transmission Line	-	-	-	-	1.4	(1.4)	-	-	1.4	-100.0%	-	0.0%
5	51181	Three Creeks Power Plant	-	-	-	-	1.0	(1.0)	-	-	1.0	-100.0%	-	0.0%
6	51440	Whitetail Peaking Station Interconnection	1.6	-	-	1.6	1.6	-	-	1.6	-	0.0%	-	0.0%
7	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
8	53034	Ksituan River 754S Capacity Upgrade	-	-	-	-	-	(0.2)	(0.2)	-	0.2	-100.0%	0.2	-100.0%
9	53595	Grande Prairie MPC Gas	-	0.9	-	0.9	-	-	-	-	0.9	100.0%	-	0.0%
10	54315	Proctor and Gamble Substation Capacity Addition	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
11	54951	HR Milner 1 & 2 Gas	-	1.3	1.3	-	-	-	-	-	1.3	100.0%	1.3	100.0%
12	53324	STS Contract Capacity Increase	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
13	53440	Thornton New POD	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
14	54954	Generator Increase	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
15	54955	Milner 2 Expansion	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
16	55119	Generator Capacity Increase	6.6	48.7	-	55.3	1.6	5.0	-	6.6	43.7	874.0%	-	0.0%
17	55145	ATCO 9L32/66	0.7	(0.7)	-	-	0.2	0.5	-	0.7	(1.2)	-240.0%	-	0.0%
18	55579	FHEC Fort Hills Substation	-	0.4	0.4	-	-	-	-		0.4	100.0%	0.4	100.0%
19	55187	Service for MacKay SAGD	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
20	55584	Green Stocking Substation	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
21	55605	Line Tap	0.3	-	-	0.3	0.2	0.1	-	0.3	(0.1)	-100.0%	-	0.0%
22	55633	55633 Surmont II (Stages 3)	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
23	55680	55680 Hangingstone SAGD	-	-	-	-	-	0.2	0.2	-	(0.2)	-100.0%	(0.2)	-100.0%
24	55709	CNRL Kirby North	-	-	-	-	0.1	-	0.1	-	-	0.0%	(0.1)	-100.0%
25	55735	Germain Substation and 144kV Line	-	-	-	-	-	3.7	3.7	-	(3.7)	-100.0%	(3.7)	-100.0%
26	56727	Pengrowth Cold Lake Area Cogen	0.6	-	-	0.6	0.6	-	-	0.6	-	0.0%	-	0.0%
27	56810	Grizzly Bear Wind Power Facility	2.2	4.1	-	6.3	2.1	0.1	-	2.2	4.0	4000.0%	-	0.0%
28	56815	Paintearth Wind Project	0.7	0.4	-	1.1	0.7	-	-	0.7	0.4	100.0%	-	0.0%
29	56820	Halkirk II Wind Power Facility	-	-	-	-	0.8	(0.8)	-	-	0.8	-100.0%	-	0.0%
30	56831	RESC Big Sky MPC Solar	-	0.5	-	0.5	-	-	-		0.5	100.0%	-	0.0%
31	56865	Wainwright	-	-	-	-	0.2	(0.2)	-	-	0.2	-100.0%	-	0.0%
32	56995	Northland Buffalo Trail WAGF	-	0.6	-	0.6	-	-	-		0.6	100.0%	-	0.0%
33	56878	SAGD Foster Creek DTS Cap Upgrade	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
34	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.4	-	-	0.4	-	0.0%	-	0.0%
35	58204	Battery Storage	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
36	58215	Wind Farm New Facility Generator Capacity	12.9	-	-	12.9	12.8	0.1	-	12.9	(0.1)	-100.0%	-	0.0%
37	58225	Garden Plain Wind	0.4	2.6	-	3.0	0.3	0.1	-	0.4	2.5	2500.0%	-	0.0%
38	58515	Joss Jenner WAGF - Phase 2	0.2	0.4	-	0.6	-	0.2	-	0.2	0.2	100.0%	-	0.0%
39	58525	Oyen Wind Energy Project	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
40	58526	Oyen Wind Power Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
41	58562	Hand Hills Wind Power Facility - 58562	-	-	-	-	0.7	(0.7)	-	-	0.7	-100.0%	-	0.0%
42	58564	BER Hand Hills MPC Wind	0.2	1.7	-	1.9	-	0.2	-	0.2	1.5	750.0%	-	0.0%
43	58569	Hand Hills Wind Power Facility	-	-	-	-	1.0	(1.0)	-	-	1.0	-100.0%	-	0.0%
44	58570	BluEarth Bindloss MPC Solar Battery	-	0.1	-	0.1								
45	58572	Hand Hills Wind Project Phase 2	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
46	58573	Hand Hills Solar	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
47	58574	Forestberg Area Solar	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
48	58578	Hand Hills WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
49	58843	Wheatland Wind New POS	0.5	2.1	-	2.6	0.5	-	-	0.5	2.1	100.0%	-	0.0%
50	58844	Echo Wind Power New POS	1.2	8.7	-	9.9	1.2	-	-	1.2	8.7	100.0%	-	0.0%
51	58922	Eyre 558S Substation Interconnection	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
52	58925	Cavendish Substation	-	(2.1)	(2.1)	-	1.0	4.4	5.4	-	(6.5)	-147.7%	(7.5)	-138.9%
53		Rounding	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
54			29.3	69.2	(0.4)	98.9	29.2	9.1	9.0	29.3	60.1	660.4%	(9.4)	200.0%
55	**OTHER TRANSMISSION**													
56	50463	Kearl 9L101	-	-	-	-	19.0	(19.0)	-	-	19.0	-100.0%	-	0.0%
57	50020	Transmission Capital Maintenance - Lines	0.1	0.2	0.2	0.1	-	0.2	0.1	0.1	-	0.0%	0.1	100.0%
58	50010	Transmission Capital Maintenance - Substations	0.1	0.3	0.4	-	0.6	-	0.5	0.1	0.3	100.0%	(0.1)	-20.0%
59		Telecom Capital Maintenance - General	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
60		Rounding				-				-	-	0.0%	-	0.0%
61			0.2	0.5	0.6	0.1	19.6	(18.8)	0.6	0.2	19.3	-102.7%	-	0.0%
62														
63			29.5	69.7	0.2	99.0	48.8	(9.7)	9.6	29.5				

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Expend	2020 Actual Expend	Variance	Var %	Variance Explanation
1	TOTAL CAPITAL MAINTENANCE		88.6	97.6	(9.0)	-9.2%	2021 expenditures are lower than prior year mainly due to Kearl 9L101 being executed in 2020 with completion in early 2021.
2	TOTAL TELECOMMUNICATION		12.7	14.4	(1.7)	-11.8%	2021 expenditures are lower than prior year mainly due to Network Multiplexor Upgrade project being substantially completed in 2020 and lower expenditures in Telecommunication Capital Maintenance and Replacement of End of Life Radios programs due to project schedule adjustments, offset by higher costs in Telecom Tower Replacements mainly due to completion of 950S Germain substation to TELUS tower facility at Chipewyan Lake fiber addition project in 2021.
3	TOTAL TRANSMISSION ISOLATED GENERATION		11.4	15.2	(3.8)	-25.0%	2021 expenditures are lower than prior year mainly due to more Alternate Power Supply/Renewable projects being in execution stage in 2020.
4	TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM		13.3	16.6	(3.3)	-19.9%	2021 capital expenditures were lower than prior year mainly due to fewer active system projects. 2020 Capital Expenditures included trailing costs for both 55737 Thickwood Development and 54904 Jasper Transmission Interconnection, which were completed in 2020. This is partially offset by higher costs in 2021 for 53043 Rycroft due to initial static VAR system (SVS) payments and detailed design activity, as well as a credit in expenditures in 54904 Jasper Transmission Interconnection related to the reversal of the accrual of shared costs of existing facilities payment after the AESO deemed that AML owed the funds and not AET.
5	TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER		22.1	14.0	8.1	57.9%	2021 capital expenditures were higher than prior year mainly due to the procurement of equipment and engineering costs in 55119 Suncor Generator Capacity Addition, partially offset by the cancellation of 58923 Currant Lake Substation and 58924 Armitage Substation.

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Adds	2020 Actual Adds	Variance	Var %	Variance Explanation
1		TOTAL CAPITAL MAINTENANCE	98.7	64.3	34.4	53.5%	2021 additions are higher than prior year mainly due to the completion of Kearl 9L101, 757S Battle River substation emergency transformer replacement, and line to ground clearance projects.
2		TOTAL TELECOMMUNICATION	16.0	12.9	3.1	24.0%	2021 additions are higher than prior year mainly due to completion of projects in the Telecommunication Capital Maintenance and Telecom Tower Replacements programs, offset by lower additions in Network Multiplexor Upgrade project being substantially completed in 2020 and schedule adjustments in Replacement of End of Life Radios.
3		TOTAL TRANSMISSION ISOLATED GENERATION	20.7	6.9	13.8	200.0%	2021 additions are higher than prior year mainly due to completing Alternate Power Supply/Renewables projects in 2020 for Chipewyan Lake Interconnection and Fort Chipewyan Renewable Energy Solution.
4		TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM	(1.9)	12.6	(14.5)	-115.1%	2021 additions were lower than prior year mainly due to trailing costs for 55737 Thickwood Development and 54904 Jasper Transmission Interconnection being significantly completed in 2020. The credit balance in additions is due to the reversal of the accrual for the shared use of existing facilities payment in 54904 Jasper Transmission Interconnection, after the AESO determined that AML owed the funds and not AET.
5		TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER	1.3	11.3	(10.0)	-88.5%	2021 capital additions were lower than prior year mainly due to the energization of 58925 Cavendish Substation occurring in 2020. There were no large projects energized in 2021.
6		TOTAL SOFTWARE	4.5	12.3	(7.8)	-63.4%	Actual capital additions were lower in 2021 compared to prior year primarily related to the completion of a portion of the Asset Management program in 2020.

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Expend	2020 Actual Expend	Variance	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	51162	Blumenort - Windy Hills 144kV Transmission Line	-	(1.4)	1.4	-100.0%	2021 Actuals are higher than prior year due to refund issued in 2020 when the project was cancelled.
3	55119	Generator Capacity Increase	48.7	5.0	43.7	874.0%	2021 Actuals are higher than prior year due to progressing from the design phase into the construction phase of the project.
4	55145	ATCO 9L32/66	(0.7)	0.5	(1.2)	-240.0%	2021 Actuals are lower than prior year due to the ATCO 9L32/66 line move project being deemed a system project which was approved in AUC Decision 24964-D02-2021 and AUC Decision 26708-D01-2021. As a result of these decisions, the contribution previously received was refunded to the customer.
5	55735	Germain Substation and 144kV Line	-	3.7	(3.7)	-100.0%	2021 Actuals are lower than prior year due to a customer requested decrease to the existing DTS rate capacity contract which resulted in additional contributions being required in 2020.
6	56810	Grizzly Bear Wind Power Facility	4.1	0.1			2021 Actuals are higher than prior year due to the project moving into the construction phase.
7	58225	Garden Plain Wind	2.6	0.1			2021 Actuals are higher than prior year due to the project moving into the construction phase.
8	58564	BER Hand Hills MPC Wind	1.7	0.2			2021 Actuals are higher than prior year due to the project moving into the construction phase.
9	58843	Wheatland Wind New POS	2.1	-			2021 Actuals are higher than prior year due to the project moving into the construction phase.
10	58844	Echo Wind Power New POS	8.7	-	8.7	0.0%	2021 Actuals are higher than prior year due to the project moving into the construction phase.
11	58925	Cavendish Substation	(2.1)	4.4	(6.5)	-147.7%	2021 Actuals are lower than prior year due to final project costs coming in lower than originally forecast, resulting in a partial contribution refund to customer.
12	54951	HR Milner 1 & 2 Gas	1.3	-			2021 Actuals are higher than prior year due to the project moving into the construction phase.
13	**TOTAL DIRECT ASSIGNED PROJECTS**		**66.4**	**12.6**	**42.4**		
14							
15	**OTHER TRANSMISSION**						
16		Kearl 9L101	-	(19.0)	19.0	-100.0%	2021 Actuals are higher than prior year due to the 9L101 Kearl line relocation costs being deemed system in 2020 rather than customer per AUC Decision 25282- D01-2020. As a result of the decision, the contribution previously received was refunded to the customer.
17	**OTHER TRANSMISSION TOTAL**		**0.0**	**(19.0)**	**19.0**		

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Adds	2020 Actual Adds	Variance	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	55735	Germain Substation and 144kV Line	0.0	3.7	(3.7)	-100.0%	2021 Actuals are lower than prior year due to a customer requested decrease to the existing DTS rate capacity contract in 2020 which resulted in additional contribution.
3	58925	Cavendish Substation	(2.1)	5.4	(7.5)	-138.9%	2021 Actuals are lower than prior year due to final project costs coming in lower than originally forecast resulting in a partial contribution refund to customer.
4	54951	HR Milner 1 & 2 Gas	1.3	0.0	1.3	0.0%	2021 Actuals are higher than prior year due to project completion in 2021.
5	**TOTAL DIRECT ASSIGNED PROJECTS**		**(0.8)**	**9.1**	**(9.9)**		

ATCO Electric Transmission (AET)
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Net Income Before Tax		203.0	203.1	(0.1)	0%	
2	Total Federal Permanent Differences		(4.2)	(4.7)	0.5	-11%	
3	Total Federal Timing Differences		(148.4)	(150.3)	1.9	-1%	
4	Total Federal Differences		(152.6)	(155.0)	2.4	-2%	
5	Total Provincial Permanent Differences		(4.2)	(4.7)	0.5	-11%	
6	Total Provincial Timing Differences		(148.3)	(150.3)	2.0	-1%	
7	Total Provincial Differences		(152.5)	(155.0)	2.5	-2%	
8	Federal Income Tax Rate		15%	15%			
9	**Total Federal Income Tax**		**7.6**	**7.2**	0.4	5%	
10							
11	Provincial Income Tax Rate		8%	9%			
12	**Total Provincial Income Tax**		**4.0**	**4.3**	(0.3)	-7%	
13							
14	**Current Tax Payable**						
15	Large Corporation and Other Tax			-			
16	Prior Year (over)/under provisions		-	(2.1)	2.1	-100%	
17	Current Year (over)/under provisions			-			
18	Other		1.3	1.5	(0.2)	-12%	
19	Current Income Tax		12.9	10.9	1.9	18%	
20	Deferred Tax- Future Income Tax		22.3	22.5	(0.3)	-1%	
21	**Corporate Income Tax**		35.1	33.5	1.7	5%	
22							
23	**Income Tax Adjustments**						
24	Tax on disallowed O&M		-	-	-	-	
25	Other		-	-	-	-	
26							
27	Utility Income Tax						
28	Effect of Normalization		-	-	-	0%	
29	**Utility Income Tax**		**35.1**	**33.5**	1.7	5.0%	

ATCO Electric Transmission (AET)

EXPLANATION OF TRANSACTIONS WITH AFFILIATED COMPANIES

FOR THE YEAR ENDED DECEMBER 31, 2021

($Millions)

Line No.	Service	Cross-Reference	Affiliate	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	**Transmission Affiliate Cost of Goods Sold**							
2	Operations & Maintenance		Alberta PowerLine	-	-	-	100.0%	
3	Engineering and Project Services		ATCO Power Canada Ltd.	-	-	-	100.0%	
4	Project and Asset Management Services		ATCO Energy Solutions Ltd.	0.3	0.2	0.1	31.3%	
5	Project and Asset Management Services		ATCO Power 2010 Ltd.	6.3	10.9	(4.6)	-42.0%	**Note 1**
6	Procurement and Supply Chain Management Services		ATCO Pipelines	0.1	-	0.1	100.0%	
7	Project Services		ATCO Pipelines	0.1	-	0.1	100.0%	
8	Tower and Circuit Leases		ATCO Gas	0.1	0.1	-	0.0%	
9	Project Services		ATCO Gas	0.1	-	0.1	100.0%	
10	Project Services		Ashcor	-	0.1	(0.1)	-100.0%	
11	Project Services		ATCO Infrastructure Solutions Ltd.	0.8	2.3	(1.5)	-64.6%	**Note 2**
12				7.8	13.6	(5.8)	-42.8%	
13	**Isolated Generation Affiliate Cost of Goods Sold**							
14	Other items individually less than $0.1			-	0.0	(0.0)	-100.0%	
15				-	0.0	(0.0)		
16	**Corporate Affiliate Cost of Goods Sold**							
17	Administrative Services		Alberta PowerLine	-	-	-	100.0%	
18	Administrative Services		Northland Utilities (NWT) Limited	1.0	0.5	0.5	94.8%	
19	Administrative Services		Yukon Electrical Company Limited	0.1	0.1	(0.0)	-13.5%	
20	Administrative Services		Northland Utilities (Yellowknife) Limited	0.0	0.1	(0.1)	-91.1%	
21				1.1	0.7	0.4	58.3%	
22								
23	**Total Affiliate Cost of Goods Sold**			**8.8**	**14.2**	**(5.4)**	-38.0%	
24								
25								
26	**Note 1:** 2021 Actuals affiliate cost of goods sold was lower than prior year due to project completion and lower project services required in 2021.							
27	**Note 2:** 2021 Actuals affiliate cost of goods sold was lower than prior year due to higher project services costs in 2020.							

ATCO Electric Transmission (AET)
SUMMARY OF PAYROLL AND MANPOWER STATISTICS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

SALARIES, WAGES AND EMPLOYEE BENEFITS

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Salaries, Wages and Employee Benefits						
2	Transmission Operations		23.8	26.7	(2.8)	-10.6%	**Note 1**
3	Transmission Capital		49.8	50.5	(0.7)	-1.4%	
4	Transmission Corporate - Operations		9.7	10.5	(0.8)	-7.8%	
5	Transmission Corporate - Capital		6.0	6.1	(0.1)	-1.4%	
6							
7	**Salaries, Wages and Employee Benefits Charged to Utility Operations**		89.3	93.7	(4.5)	-4.8%	

EMPLOYEE ALLOCATION

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
8	Manpower Statistics						
9	Total Regular Employees (FTEs)		535.1	557.1	(22.1)	-4.0%	
10	Total Temporary Employees (FTEs)		25.1	18.4	6.7	36.5%	
11	**Total Manpower**		560.2	575.5	(15.3)	-2.7%	
12	Less:						
13	Allocated to Non-regulated		-	-			
14	**Total Manpower - Utility Operations**		560.2	575.5			
15							

16 **Variance Explanations**

17

18 **Note 1:** Salaries, Wages, and Employee Benefits are lower than prior year due to decreased workload requirements primarily related to maintenance activities.

ATCO Electric Transmission (AET)
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Ref.	2021 Actual Opening Balance	Adds	Provision	Adjustments	Ending Balance	Working Paper Reference
1	List of Reserve/Deferral Accounts							
2								
3	Reserve for Injuries and Damages		(0.2)	-	0.8	-	0.6	
4	Variable Pay Program (VPP)		4.3	(4.2)	4.4	-	4.4	
5	Vegetation Management		(0.1)	(5.2)	5.2	-	(0.1)	
6								
7	**Total Deferred Assets**		4.0	(9.4)	10.4	-	4.9	
8								
9	Federal Future Income Tax		238.2	5.8	24.0	-	268.0	
10								
11	**Total Deferred Liabilities**		238.2	5.8	24.0	-	268.0	

ATCO Electric Transmission (AET)
RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
1	**Revenues**		**1,231.0**	**(442.7)**	**941.0**	**732.7**		
2								
3	Impact of AUC Decisions						4.7	
4	Eliminate Non-Utility Revenues						(5.3)	
5	Adjustment of Customer Contribution for KXL Cancelled Project						(13.5)	
6	Reclassification of Revenue Offsets						(20.3)	
7	Reclass of Amortization of Contributions to Depreciation						(10.7)	
8	Non IFRS Deferral Revenue						(3.3)	
9	Other						2.2	
10								
11		Sch 1.0-T	1,231.0	(442.7)	941.0	732.7	(46.3)	**686.4**
12								
13	**Cost of Sales**		**-**	**(433.1)**	**433.1**	**-**		
14								
15								
16			-	(433.1)	433.1	-	-	**-**
17								
18	**Fuel**		**3.1**	**-**	**0.0**	**3.1**		
19								
20								
21		Sch 1.0-T	3.1	-	0.0	3.1	-	**3.1**
22								
23								
24	**Operating and Maintenance**		**441.7**	**0.9**	**224.0**	**216.8**		
25								
26	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						(9.8)	
27	Non-recovered (Disallowed) Utility Costs						(5.8)	
28	AUC Enforcement - Penalty						(31.0)	
29	AUC Enforcement - Write-Off of Capital Project Costs						(10.8)	
30	AUC Enforcement - Legal/Other						(1.2)	
31	Farms Reclassification						(4.6)	
32	Reclassification of Other Cancelled Projects from Depreciation						1.5	
33	Reclassification of Credit Facility fees from Financing						1.1	
34	Other						0.3	
35								
36		Sch 1.0-T	441.7	0.9	224.0	216.8	(60.3)	**156.5**
37								

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
38	**Depreciation and Amortization**		**311.6**	**(8.0)**	**134.1**	**185.5**		
39								
40	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						48.5	
41	Reclass of Amortization of Contributions to Depreciation						(10.7)	
42	Farms Reclassification						1.4	
43	Reclassification of Other Cancelled Projects to O&M						(1.5)	
44	Non-Utility Depreciation						(0.8)	
45	Depreciation Relating to AUC Enforcement - Capital Write-Off						(0.4)	
46	Impact of AUC Decisions						1.4	
47	Adjustment of KXL Cancelled Project Write-Off						(10.4)	
48	Other						(4.3)	
49								
50		Sch 1.0-T	311.6	(8.0)	134.1	185.5	23.3	**208.8**
51								
52	**Income Tax**		**65.0**	**(0.6)**	**17.9**	**47.7**		
53								
54	Tax on Adjustments	Note 2					(12.6)	
55								
56		Sch 1.0-T	65.0	(0.6)	17.9	47.7	(12.6)	**35.1**
57								
58	**Revenue Offsets**		**-**	**-**	**-**	**-**		
59								
60	Reclassification of Revenue Offsets						20.3	
61								
62		Sch 1.0-T	-	-	-	-	20.3	**20.3**
63								
64	**Return**		**409.5**	**(2.0)**	**132.0**	**279.5**		
65	Adjustments	Note 1					23.7	
66		Sch 1.0-T	409.5	(2.0)	132.0	279.5	23.7	**303.2**
67								
68	**Note 1 - Return Adjustments**							
69	Long Term Debt & Other		**218.8**	**-**	**66.6**	**152.2**		
70	Adjustment for IFRS IDC Treatment						(3.2)	
71	Credit facility Reclass to O&M						(1.1)	
72	Adjustment for KXL Cancelled Project						(3.1)	
73	Financing Other						(4.4)	
74			218.8	-	66.6	152.2	(11.8)	**140.4**
75								
76	Preferred Shares		**-**	**-**	**-**	**-**		
77							2.8	
78			-	-	-	-	2.8	**2.8**
79								
80	Return on Equity		**190.7**	**(2.0)**	**65.4**	**127.3**		
81		Note 2					32.6	
82			190.7	(2.0)	65.4	127.3	32.6	**159.9**
83								
84	**Total Return Adjustments**		**409.5**	**(2.0)**	**132.0**	**279.5**	**23.7**	**303.2**

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)

FOR THE YEAR ENDED DECEMBER 31, 2021

INCOME STATEMENT ITEMS

($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
85								
86							**(Return)**	
87	**Note 2 - Return on Equity Adjustments**					**Before tax**	**After tax**	**Tax impact**
88								
89	**Financing & Subs**							
90	Preferred Dividends					(2.8)	(2.8)	
91	IDC					6.3	4.9	**1.5**
92	Interest and Other					5.5	4.2	**1.3**
93								
94	**Income Tax**							
95	Income Tax (Provincial Future Tax for IFRS)						13.0	**(13.0)**
96	Income Tax (T2S1 Additions & Deductions Non Regulatory)						(0.3)	**0.3**
97	Income Tax (T2S1 Additions & Deductions Non IFRS)						(0.0)	**0.0**
98	Income Tax (Book to Filing)						(1.1)	**1.1**
99	Income Tax (T2S1 Other)						6.2	**(6.2)**
100								
101	**Other Income Statement Items**							
102	Revenue Tax Impact					(25.9)	(20.0)	**(6.0)**
103	O&M Tax Impact					60.3	46.4	**13.9**
104	Depreciation Tax Impact					(23.3)	(17.9)	**(5.4)**
105								
106						20.0	32.6	**(12.6)**

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(Transmission and Distribution)
FOR THE YEAR ENDED DECEMBER 31, 2021
BALANCE SHEET ITEMS
($Millions)

Line No.		Description	Cross-Reference	Audited Financial Statements	Adjustments	Total
1	**Assets**					
2		Current Assets				
3		Cash and short term investments		18.5	-	18.5
4		Accounts receivable		147.6	(0.4)	147.2
5		Income taxes		0.2	757.6	757.8
6		Inventories		3.8	-	3.8
7		Prepaid expenses		6.2	-	6.2
8						
9		Property, plant and equipment		9,853.7	(1,844.9)	8,009
10						
11		Investments		131.5	(16.5)	114.9
12						
13		Regulatory Assets		-	103.6	103.6
14		Deferred financing Charges		-	27.2	27.2
15		Other		-	-	-
16						
17		**Total Assets**		**10,161.4**	**(973.4)**	**9,188.0**
18						
19						
20	**Liabilities**					
21		Current Liabilities				
22		Bank Indebtedness		-	-	-
23		Short term advances from parent and affiliated corporations		57.7	-	57.7
24		Accounts payable and accrued liabilities		160.3	(0.6)	159.7
25		Owing to parent and affiliated corporations		72.7	-	72.7
26		Income taxes payable		0.0	0.0	0.0
27		Regulatory Liabilities		-	-	-
28		Long term debt		50.0	(50.0)	-
29						
30		Future income taxes		949.5	(5.8)	943.7
31		Regulatory Liabilities		-	-	-
32		Long term debt		5,006.3	(26.8)	4,979.5
33		Other		1,107.1	(1,041.4)	65.7
34						
35		**Total Liabilities**		**7,403.6**	**(1,124.6)**	**6,279.0**
36						
37	**Equity**					
38		Equity preferred shares to Parent Corporation		98.3	1.7	100.0
39						
40		Class A and Class B shares owner's equity				
41		Class A and Class B shares		1,212.4	-	1,212.4
42		Retained earnings		1,447.1	149.4	1,596.6
43		**Total Equity**		**2,757.9**	**151.1**	**2,909.0**
44						
45		**Total Liabilities and Share Owner's Equity**		**10,161.4**	**(973.4)**	**9,188.0**

ATCO Electric Transmission (AET)
Summary of Pension Plan Contributions
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

ATCO Electric has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

<u>2021 Actual</u>

	Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 1)	1.3	-	3.6	**4.9**
ATCO Other	2.5	-	6.1	**8.6**

Note 1 - The actual defined benefit and defined contribution service amounts along with the special payment do not include amounts that are allocated from the ATCO Head office.
This amount includes COLA at 100%

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.
Accordingly the deferral account should be calculated as the annual difference between the amounts collected in rates in respect of the special payments and the special payment amounts actually paid by ATCO Utilities pursuant to the Pension Valuation(s) accepted by the Superintendent of Pensions that were in force during such year.

<u>2020 Reconciliation (ATCO Electric - Transmission)</u>	
2020 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 2)	-
2020 Actual Special Payment Pension contributions	-
2020 Actual Special Payment Pension contributions - allocated from ATCO Head Office	-
Refund/(collection) to / (from) customers	-

Note 2 - Per ATCO Electric Transmission 2020-2022 GTA Compliance Filing (Exhibit 24964-X0003, Attachment 3, Schedule 3, Line 6

<u>2021 Reconciliation (ATCO Electric - Transmission)</u>	
2021 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 3)	-
2021 Actual Special Payment Pension contributions	-
2021 Actual Special Payment Pension contributions - allocated from ATCO Head Office	-
Refund/(collection) to / (from) customers	-

Note 3 - Per ATCO Electric Transmission 2020-2022 GTA Post Disposition Filing (Exhibit 26477-X0010, Attachment 3, Schedule 3, Line 6
Pension information can be found per ATCO Electric Transmission's 2020-2022 GTA filing. Exhibit 24964-X0001, Section 1.6 - Deferral and Reserve Accounts - Defined Benefit Pension Plan Funding

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2020 CU Pension Plan Report dated August 11, 2021, was filed with the Superintendent of Pensions.

April 29, 2022

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Attention: Kristjana Kellgren,
Executive Director, Rates Division

Re: ATCO Electric Transmission
AUC Rule 005
Annual Reporting of Financial and Operational Results

In accordance with the Alberta Utilities Commission (AUC or the Commission) Rule 005, please find enclosed ATCO Electric Transmission's (AET) 2021 Annual Reporting of Financial and Operational Results.

Should you have any questions or require further information regarding this submission, please do not hesitate to contact the undersigned at lisa.brennand@atco.com.

Yours truly,

Lisa Brennand, CPA, CA
Director, Regulatory

ATCO Electric Transmission (AET)

SUMMARY OF REVENUE REQUIREMENT

FOR THE YEAR ENDED DECEMBER 31, 2021

($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Return on Rate Base	Sch 2.0-T	303.2	309.6	(6.4)	-2.1%	
2	Fuel		3.1	3.5	(0.4)	-10.4%	
3	Operating and Maintenance	Sch 3.0-T	156.5	167.7	(11.3)	-6.7%	
4	Depreciation and Amortization	Sch 4.0-T	208.8	210.8	(2.0)	-1.0%	
5	Utility Income Tax	Sch 5.0-T	35.1	33.5	1.7	5.0%	
6	Subtotal		706.7	725.2	(18.4)	-2.5%	
7							
8	Revenue Offsets		(20.3)	(27.2)	6.9	-25.3%	
9							
10	**Total Transmission Revenue Requirement**	Sch 10	686.4	697.9	(11.5)	-1.7%	
11							
12							
13	Detailed Revenue Requirement						
14	Transmission Tariff Revenue*		689.7	698.1	(8.4)	-1.2%	
15	Deferral Account		(3.3)	(0.2)	(3.1)	1566.0%	**Note 1**
16	**Total Transmission Revenue Requirement**	Line 10	686.4	697.9	(11.5)	-1.6%	
17							

18 * The 2021 Tariff Revenue is AET's 2021 Tariff as Approved within the 2020-2022 GTA Post Disposition Filing (Exhibit PD-26477-X0011.02).

19

20 **Variance Explanations**

21

22 **Note 1:** 2021 Actuals (refunds) are higher by ($3.1M) due to the annual true up of deferral accounts. The difference is mainly due to higher refunds of the Direct Assign Capital deferral ($2.8M), Capital Repair deferral ($0.7M), and ROW deferral ($0.1M), offset by a lower refund of the Property Tax deferral ($0.5M). Balances accumulated in the deferral account will be applied for in AET's 2021 Transmission Deferral Settlement filed within its 2023-2025 GTA, Proceeding 27062.

23

24

25 **Reference to Approved Forecast**

26

27 Please refer to AET's 2020-2022 GTA Compliance Post Disposition Filing (Exhibit PD-26477-X0011.02) for the Approved forecasts for 2020 and 2021.

ATCO Electric Transmission (AET)
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actuals

Line No.	Description	Cross-Reference	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $	Working Paper Reference
1	Return on Long Term Debt (Farms Irrigation Transmission)				11.7	5.82%	0.7	
2	Return on Equity (Farms, Irrigation Transmission)				20.3	5.82%	1.2	
3	**Mid Year Rate Base (Farms, Irrigation Transmission)**				32.0	5.82%	1.9	
4								
5	**Mid Year Rate Base**							
6	Long-Term Debt	Sch 2.2-T	3,216.5	61.51%	3,063.5	4.56%	139.7	
7	Preferred Shares	Sch 2.2-T	77.7	1.49%	74.0	3.85%	2.9	
8	Common Equity	Sch 2.2-T	1,934.7	37.00%	1,842.7	8.61%	158.7	
9	**Mid-Year Net Rate Base**	Sch 1.0-T	5,229.0	100.00%	4,980.3	6.09%	303.2	
10	Contribution for Extensions				521.4			
11	No Cost Capital	Sch 2.1-T			257.6			
12	**Mid Year Rate Base**				5,759.2			

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Gross Utility Plant in Service						
2	Opening Balance	Sch 4.1-T	7,664.3	7,575.4	88.8	1.2%	
3	Closing Balance	Sch 4.1-T	7,759.5	7,678.8	80.6	1.0%	
4	**Mid-Year Gross Utility Plant in Service**		7,711.9	7,627.1	84.7	1.1%	
5							
6	Accumulated Depreciation - Utility						
7	Opening Balance	Sch 4.1-T	1,918.7	1,728.3	190.3	11.0%	
8	Closing Balance	Sch 4.1-T	2,082.5	1,922.0	160.5	8.3%	
9	**Mid-Year Accumulated Depreciation - Utility**		2,000.6	1,825.2	175.4	9.6%	
10							
11	Contributions in Aid of Construction						
12	Opening Balance		529.9	529.7	0.2	0.0%	
13	Closing Balance		516.1	529.9	(13.8)	-2.6%	
14	**Mid-Year Utility Contributions in Aid of Construction**		523.0	529.8	(6.8)	-1.3%	
15							
16	Amortization of Contributions						
17	Opening Balance		67.6	58.0	9.5	16.4%	
18	Closing Balance		64.2	67.6	(3.3)	-5.0%	
19	**Mid-Year Utility Amortization of Contributions**		65.9	62.8	3.1	4.9%	
20							
21							
22	**Mid-Year Net Utility Plant in Service**		5,254.2	5,335.0	(80.8)	-1.5%	
23							
24	Necessary Working Capital		47.9	50.6	(2.7)	-5.2%	
25							
26	No Cost Capital		(257.6)	(229.7)	(27.9)	12.1%	**Note 1**
27							
28	**Mid-Year Net Rate Base**		5,044.5	5,155.9	(111.3)	(0.0)	
29							
30	Mid-Year Contributions CWIP	Sch. 4.2T Contributions	(64.3)	(39.2)	(25.1)	64.1%	
31							
32	**Total Mid-Year Rate Base and CWIP**	Sch. 2.0-T	**4,980.3**	**5,116.7**	(136.4)	-2.7%	
33							
34							
35	**Variance Explanations**						
36							
37	**Note 1**: 2021 Actuals are higher than 2020 Actuals by ($27.9M) mainly due to an increase in the federal future income tax reserve balance.						

ATCO Electric Transmission (AET)
SUMMARY OF MID-YEAR CAPITAL STRUCTURE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	Current Year-End	Previous Year-End	Actual Mid-Year Capital	Working Paper Reference
1	Long-Term Debt	Sch 2.3	3,200.3	3,232.7	3,216.5	
2	Preferred Shares	Sch 2.4	63.8	91.7	77.7	
3	Common Equity		1,834.5	2,034.9	1,934.7	
4						
5	**Total Mid-Year Invested Capital**		**5,098.6**	**5,359.4**	**5,229.0**	

ATCO Electric Transmission (AET)
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		LT Adv. -Parent											
2			Z	1991-12-18	2022	9.9%	29.3	0.4	29.0	10.0%	29.3	2.9	
3			AA	1992-12-08	2023	9.4%	13.8	0.1	13.7	9.4%	13.8	1.3	
4			2004	2004-11-18	2034	5.9%	71.1	0.4	70.6	5.9%	70.8	4.2	
5			2005	2005-11-30	2035	5.2%	56.3	0.4	56.0	5.2%	56.1	2.9	
6			2006	2006-11-20	2036	5.0%	59.3	0.4	58.9	5.1%	59.0	3.0	
7			2007	2007-11-01	2037	5.6%	79.2	0.5	78.7	5.6%	78.9	4.4	
8			2008	2008-05-26	2028	5.6%	29.3	0.2	29.1	5.6%	29.2	1.6	
9			2008	2008-05-26	2038	5.6%	44.0	0.3	43.7	5.6%	43.8	2.5	
10			2009	2009-03-06	2024	6.2%	68.1	0.4	67.6	6.3%	68.0	4.3	
11			2009	2009-03-07	2039	6.5%	85.7	0.6	85.1	6.6%	85.2	5.6	
12			2010	2010-11-10	2050	4.9%	73.3	0.5	72.8	5.0%	72.9	3.6	
13			2011	2011-10-24	2041	4.5%	192.8	1.2	191.6	4.6%	191.9	8.8	
14			2011	2011-10-24	2061	4.6%	77.1	0.5	76.6	4.6%	76.7	3.6	
15			2012	2012-09-10	2042	3.8%	317.3	2.0	315.3	3.8%	315.7	12.1	
16			2012	2012-09-10	2062	3.8%	126.8	0.8	126.0	3.9%	126.0	4.9	
17			2012	2012-11-14	2052	3.9%	161.2	1.0	160.2	3.9%	160.3	6.2	
18			2013	2013-09-09	2043	4.7%	241.0	1.6	239.4	4.8%	239.7	11.4	
19			2013	2013-09-18	2063	4.9%	75.0	0.6	74.4	4.9%	74.4	3.7	
20			2013	2013-11-07	2053	4.6%	225.0	1.4	223.6	4.6%	223.7	10.3	
21			2014	2014-09-05	2044	4.1%	555.0	3.5	551.5	4.1%	552.0	22.8	
22			2014	2014-10-17	2054	4.1%	180.0	1.2	178.8	4.1%	178.9	7.4	
23			2015	2015-07-27	2045	4.0%	110.0	0.8	109.2	4.0%	109.3	4.4	
24			2015	2015-10-29	2055	4.2%	185.0	1.3	183.7	4.3%	183.8	7.8	
25			2018	2018-11-21	2048	4.0%	90.0	0.6	89.4	4.0%	89.4	3.6	
26			2019	2019-09-05	2049	3.0%	72.0	0.5	71.5	3.0%	71.5	2.1	
27											3,200.3	145.5	4.5%
28													
29		Short-term Debt / (Investment)				0.8%	-		-	0.8%	-	-	
30													
31		2021 Ending Balance									3,200.3	145.5	4.5%
32		2021 Opening Balance									3,232.7	148.0	4.6%
33		**Mid-Year Balance**									**3,216.5**	**146.7**	**4.6%**

ATCO Electric Transmission (AET)
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

2021 Actual

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Underwriting Discount & Expense	Net Proceeds Outstanding	Carrying Cost of Issue	Average Embedded Cost Rate
1		1	2007	4.60%	38.9	-	38.9	1.8	4.60%
2		4	2010	2.29%	24.9	-	24.9	0.6	2.29%
3									
4		Current Year-End Balance			63.8	-	63.8	2.4	3.70%
5		Prior Year-End Balance			91.7	-	91.7	3.6	3.96%
6		Total			155.5		155.5	6.0	3.85%
7		Mid-Year Balance			77.7		77.7	3.0	3.85%

8
9 **Note:**
10 Series V Preferred Shares were redeemed on August 27, 2021.
11 Series 4 Preferred Shares reset in 2021.

ATCO Electric Transmission (AET)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Acct No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1		**Direct Operation & Maintenance Expense**						
2	560	Supervision and Engineering		3.0	3.4	(0.3)	-10.1%	
3	561	Control Centre Operations		4.9	4.8	0.0	1.0%	
4	562	Station Equipment Expenses		8.6	9.1	(0.5)	-5.6%	**Note 1**
5	563/569	Overhead Lines Expenses & Operation Maintenance		2.7	2.7	(0.1)	-2.3%	
6	566	Miscellaneous Transmission Expense		28.7	33.5	(4.8)	-14.3%	**Note 2**
7	567	Right of Way Payments		6.7	6.8	(0.1)	-1.3%	
8	571.1	Vegetation Management		5.2	7.9	(2.7)	-34.2%	**Note 3**
9	575	IT Support		-	-	-	0.0%	**Note 4**
10		Total Direct Operation & Maintenance Expense		59.8	68.3	(8.5)	-12.4%	
11								
12		**Isolated Generation Operation & Maintenance**						
13	537	Hydro Expenses		-	0.0	(0.0)	-100.0%	
14	546	Combustion Engines/Turbine Operations		1.0	1.2	(0.2)	-17.1%	
15	554	Combustion Engines/Turbine Maintenance		0.6	0.7	(0.0)	-4.1%	
16	557	Other Expenses		0.2	0.5	(0.3)	-58.7%	
17		Total Isolated Generation Operation & Maintenance		1.8	2.3	(0.5)	-22.1%	
18								
19		**Administrative and General**						
20	920	General Administration		11.8	12.8	(1.1)	-8.2%	
21	921	Office Supplies and Expenses		5.0	4.6	0.3	7.5%	
22	923	Outside Services Employed		0.5	0.6	(0.1)	-21.5%	
23	924	Insurance Premiums		4.3	3.7	0.6	17.0%	
24	925	Injuries and Damages		0.8	0.8	-	0.0%	
25	928	Board Expenses		1.2	1.2	0.0	0.0%	
26	930.2	Miscellaneous General Expenses		16.1	15.9	0.3	1.6%	
27	931.1	Head Office Rent		1.3	1.4	(0.1)	-5.9%	
28	934	IT G&A Expense		12.8	15.6	(2.8)	-18.1%	**Note 5**
29	941	Board Expenses Disallowed		0.7	1.0	(0.3)	-28.6%	
30	935.2	Maintenance Company Owned Houses		0.2	0.1	0.1	54.9%	
31				54.7	57.8	(3.1)	-5.4%	
32		Non-utility Items		(5.9)	(5.8)	(0.1)	1.5%	
33		Total Administrative and General		48.7	51.9	(3.2)	-6.1%	
34								
35		Taxes Other Than Income		45.4	44.5	0.9	2.1%	
36								
37		Farms, Irrigation Transmission Operating Costs		0.6	0.7	(0.1)	-7.8%	
38								
39		**Total Transmission O&M Costs**	Sch 1.0-T	**156.5**	**167.7**	**(11.3)**	**-6.7%**	
40								

41 **Variance Explanations**

42

43 **Note 1** 2020 Actuals have been restated from $9.3 to $9.1 due to the reclassification of IT costs to USA 934.

44

45 **Note 2** 2021 Actuals are lower than 2020 Actuals by ($4.8) mainly due to lower affiliate cost of goods sold for affiliate work ($5.6) and SOP for Alberta
46 PowerLine ($1.4), partially offset by cancelled projects write-offs ($1.6), higher SOP cost of goods sold ($0.3) and labour ($0.2). Affiliate and SOP
47 cost of goods sold are offset by affiliate revenue and have no impact on revenue requirement.

48

49 **Note 3** 2021 Actuals are lower than 2020 Actuals by ($2.7) mainly due to reduction in mechanical and herbicide treatment area resulting from the transition
50 to a full herbicide cycle.

51

52 **Note 4** 2020 Actuals have been restated from $2.8 to nil due to the reclassification of IT costs to USA 934.

53

54 **Note 5** 2021 Actuals are lower than 2020 Actuals by ($2.8) mainly due to lower IT transition costs associated with the realignment of IT services.

ATCO Electric Transmission (AET)
SUMMARY OF DEPRECIATION EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Transmission		194.8	196.8	(2.0)	-1.0%	
2	Amortization of Differences		4.4	4.4	0.0	0.0%	
3	**Subtotal**		199.2	201.2	(2.0)	-1.0%	
4							
5	**Direct General PP&E**						
6	Structures & Improvements		3.1	3.1	(0.0)	-0.7%	
7	Office Furniture and Equipment		0.8	0.8	(0.0)	-1.0%	
8	Computer Equipment		0.5	0.2	0.3	107.3%	
9	Transportation Equipment		3.4	3.1	0.3	10.5%	
10	Tools & Instruments		3.4	3.5	(0.0)	-1.2%	
11	Leasehold Improvements		1.2	1.1	0.0	2.5%	
12	Software		8.4	8.5	(0.1)	-1.0%	
13	Amortization of Differences		0.3	0.3	0.0	0.0%	
14	**Subtotal**		21.1	20.7	0.5	2.2%	
15							
16							
17	**Transmission Gross Provision**		220.3	221.9	(1.5)	-0.7%	
18							
19	Farms, Irrigation Transmission		1.4	1.5	(0.1)	-6.5%	
20							
21	**Total Transmission Gross Depreciation Expense**		221.7	223.3	(1.6)	-0.7%	
22							
23							
24	Gross Depreciation Expense		221.7	223.3	(1.6)	-0.7%	
25	Vehicle Depreciation Capitalized		(2.3)	(2.0)	(0.3)	15.5%	
26	Amortization of Contributions		(10.7)	(10.6)	(0.1)	0.8%	
27	**Total Depreciation and Amortization Expense**		208.8	210.8	(2.0)	-1.0%	
28							
29							
30	**Total Depreciation and Amortization Expense**	Sch 1.0-T	208.8	210.8	(2.0)	-1.0%	

ATCO Electric Transmission (AET)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Prior years' Disallowances	Prior Year Disallowances & Opening Balance Adjustments	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	2021 Pension Disallowance	Balance at 12/31/2021
1	Transmission		7,358.4	(14.6)	7,343.8	129.3	(39.5)	-	0.4	(0.1)	7,433.9
2											
3	**Direct General PP&E**										
4	Land		4.8	-	4.8	-	-	-	(0.0)	-	4.8
5	Structures and Improvements		121.5	(0.0)	121.5	0.7	(0.5)	-	(0.0)	-	121.7
6	Office Furniture and Equipment		12.6	-	12.6	0.1	(0.2)	-	-	-	12.6
7	Computer Equipment		1.9	-	1.9	1.7	(0.3)	-	-	-	3.3
8	Transportation Equipment		57.5	-	57.5	5.1	(3.1)	(0.1)	-	-	59.4
9	Tools and Instruments		34.0	-	34.0	2.2	(1.7)	-	-	-	34.5
10	Leasehold Improvements		11.6	-	11.6	0.2	0.1	-	-	-	11.8
11	Software		76.5	-	76.5	2.9	(2.0)	-	-	-	77.4
12	**Subtotal**		320.5	(0.0)	320.5	12.9	(7.7)	(0.1)	(0.0)	-	325.6
13											
14	**Subtotal - Utility Plant in Service**	Sch 2.1-T	7,678.8	(14.6)	7,664.3	142.2	(47.2)	(0.1)	0.4	(0.1)	7,759.5
15											
16	Capital Work in Progress (CWIP)		152.2	-	152.2	17.4	-	-	-	-	169.6
17											
18	**Total Transmission**		7,831.0	(14.6)	7,816.5	159.6	(47.2)	(0.1)	0.4	(0.1)	7,929.1
19											
20											

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Disallowances	Prior Year Disallowances & Opening Balance Adjustments	Depreciation Provision	2021 Retirements	2021 Transfers	2021 Adjustments	2021 Net Salvage	Balance at 12/31/2021
21	Transmission		1,799.2	(3.3)	1,795.9	199.2	(39.5)	-	(1.7)	(7.9)	1,945.9
22											
23	**Direct General PP&E**										
24	Land		0.0	-	0.0	-	-	-	-	-	0.0
25	Structures and Improvements		27.7	(0.0)	27.7	3.2	(0.5)	-	(0.0)	(0.1)	30.4
26	Office Furniture and Equipment		6.9	-	6.9	0.8	(0.2)	-	-	-	7.5
27	Computer Equipment		0.6	-	0.6	0.5	(0.3)	-	-	-	0.8
28	Transportation Equipment		26.4	-	26.4	3.2	(3.1)	(0.1)	-	0.7	27.1
29	Tools and Instruments		16.9	-	16.9	3.6	(1.7)	-	-	-	18.8
30	Housing		0.5	-	0.5	-	-	-	-	-	0.5
31	Leasehold Improvements		3.3	-	3.3	1.4	0.1	-	-	(0.0)	4.7
32	Software		40.4	-	40.4	8.4	(2.0)	-	(0.2)	-	46.6
33	**Subtotal**		122.8	(0.0)	122.8	21.1	(7.7)	(0.1)	(0.2)	0.6	136.6
34											
35	**Total Transmission**	Sch 2.1-T	1,922.0	(3.3)	1,918.7	220.3	(47.2)	(0.1)	(1.9)	(7.3)	2,082.5
36											
37											
38											
39	**Note:** AFUDC is a component of all categories and is therefore not disclosed separately in this continuity schedule.										

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
1		**CAPITAL MAINTENANCE**												
2		Transmission Capital Maintenance - Substations	17.3	31.4	33.2	15.5	20.2	25.1	28.0	17.3	6.3	25.1%	5.2	18.6%
3		Transmission Capital Maintenance - Lines	11.0	16.2	24.1	3.1	3.1	31.3	23.4	11.0	(15.1)	-48.2%	0.7	3.0%
4		Transmission System Right-of-Way	0.1	2.3	2.3	0.1	-	2.1	2.0	0.1	0.2	9.5%	0.3	15.0%
5		Transmission Rights-of-Way Widening	0.5	4.8	4.5	0.8	-	4.9	4.4	0.5	(0.1)	-2.0%	0.1	2.3%
6		Substation Rebuilds	3.1	12.5	5.0	10.6	0.9	6.4	4.2	3.1	6.1	95.3%	0.8	19.0%
7		Transmission Line Ground Clearance	4.4	4.8	5.5	3.7	1.0	5.6	2.2	4.4	(0.8)	-14.3%	3.3	100.0%
8		Transmission Line Rebuilds (Partial & Complete)	13.5	8.3	-	21.8	7.9	5.6	-	13.5	2.7	48.2%	-	0.0%
9		Kearl 9L101	18.9	5.1	24.0	-	2.6	16.3	-	18.9	(11.2)	-68.7%	24.0	100.0%
10		Transmission Double Circuit	0.1	-	0.1	-	0.4	(0.2)	0.1	0.1	0.2	-100.0%	-	0.0%
11		ATCO 9L32/66 Line Move	0.4	2.7	-	3.1	0.1	0.3	-	0.4	2.4	100.0%	-	0.0%
12		Temporary Line Relocation- 9L66/9L92 (Phase 2 Joslyn - Muskeg)	0.6	0.3	-	0.9	0.4	0.2	-	0.6	0.1	50.0%	-	0.0%
13		Youngstown Substation Purchase	0.1	0.2	-	0.3	0.1	-	-	0.1	0.2	100.0%	-	0.0%
14			70.0	88.6	98.7	59.9	36.7	97.6	64.3	70.0	(9.0)	-9.2%	34.4	53.5%
15		**TELECOMMUNICATION**												
16		Telecommunication Capital Maintenance	4.5	5.4	8.8	1.1	1.7	7.0	4.2	4.5	(1.6)	-22.9%	4.6	100.0%
17		Mobile Communication System	-	-	-	-	0.3	(0.3)	-	-	0.3	-100.0%	-	0.0%
18		Network Multiplexor Upgrade	-	0.2	0.2	-	0.2	0.7	0.9	-	(0.5)	-71.4%	(0.7)	-77.8%
19		Telecom Tower Replacements	0.4	1.8	2.1	0.1	0.1	0.6	0.3	0.4	1.2	100.0%	1.8	100.0%
20		Telecom Building Replacements/Refurbishments	-	0.2	0.0	0.2	0.1	-	0.1	-	0.2	100.0%	(0.1)	-79.0%
21		Replacement of End of Life Radios	2.0	3.7	3.3	2.4	3.0	4.5	5.5	2.0	(0.8)	-17.8%	(2.2)	-40.0%
22		Telecom Capacity & Reliability Upgrade Projects	0.9	1.3	1.1	1.1	0.5	1.6	1.2	0.9	(0.3)	-18.8%	(0.1)	-8.3%
23		Mobile Radio Expansion	0.4	0.1	0.5	-	0.8	0.3	0.7	0.4	(0.2)	-66.7%	(0.2)	-28.6%
24		Various Other Projects Below $0.0 individually - Telecom	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
25			8.2	12.7	16.0	4.9	6.7	14.4	12.9	8.2	(1.7)	-11.8%	3.1	24.2%
26		**SCADA / EMS**												
27		Operational Information Systems	0.5	1.1	1.6	-	0.3	0.8	0.6	0.5	0.3	37.5%	1.0	100.0%
28		Regulatory Compliance & Security Programs	1.0	1.0	0.3	1.7	1.2	1.6	1.8	1.0	(0.6)	-37.5%	(1.5)	-83.3%
29			1.5	2.1	1.9	1.7	1.5	2.4	2.4	1.5	(0.3)	100.0%	(0.5)	-20.8%
30														
31		**TRANSMISSION ISOLATED GENERATION**												
32		Install Alternate Power Supply/Renewables	12.5	9.2	19.5	2.2	3.9	12.9	4.3	12.5	(3.7)	-28.7%	15.2	100.0%
33		Rebuild Jasper Palisades Substation	0.3	-	0.2	0.1	0.3	-	-	0.3	-	0.0%	0.2	100.0%
34		Refurbish/Replace Engines and Turbines	0.7	0.5	1.0	0.2	1.0	1.0	1.3	0.7	(0.5)	-50.0%	(0.3)	-23.1%
35		Transmission Isolated Operations Capital Maintenance	0.4	1.7	-	2.1	0.4	1.3	1.3	0.4	0.4	30.8%	(1.3)	-100.0%
36			13.9	11.4	20.7	4.6	5.6	15.2	6.9	13.9	(3.8)	-25.0%	13.8	100.0%
37														

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
38		**NORTH WEST FIRE 2019**	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
39														
40		**TOTAL CAPITAL MAINTENANCE**	93.6	114.8	137.3	71.1	50.5	129.6	86.5	93.6	(14.8)	-11.4%	50.8	58.8%
41														
42		**DIRECT ASSIGNED PROJECTS SYSTEM**												
43	53043	Rycroft Transmission Reinforcement	1.7	5.7	-	7.4	1.2	0.5	-	1.7	5.2	100.0%	-	0.0%
44	53320	High Prairie to Triangle 144 kV Line Upgrade	-	(0.2)	(0.2)	-	-	-	-	-	(0.2)	-100.0%	(0.2)	-100.0%
45	53594	Grande Prairie Transmission Reinforcement	0.2	-	-	0.2	0.2	-	-	0.2	-	0.0%	-	0.0%
46	54904	Jasper Transmission Interconnection	-	(2.8)	(2.8)	-	-	6.3	6.3	-	(9.1)	-100.0%	(9.1)	-100.0%
47	54906	Jasper Palisade (781S) Substation Decommissioning	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
48	55145	ATCO 9L32/66	0.1	4.2	-	4.3	-	0.1	-	0.1	4.1	100.0%	-	0.0%
49	55737	Thickwood Development	-	0.6	0.6	-	-	5.8	5.8	-	(5.2)	-89.7%	(5.2)	-89.7%
50	55900	P7071 and P7072 Voice and Data Upgrades	-	0.2	-	0.2	-	-	-	-	0.2	100.0%	-	0.0%
51	56772	Nevis Transformer	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
52	57157	St. Paul Substation & Line	-	0.1	0.1	-	-	-	-	-	0.1	100.0%	0.1	100.0%
53	57159	PENVTD	3.0	2.2	-	5.2	1.1	1.9	-	3.0	0.3	15.8%	-	0.0%
54	57180	57180 Time Domain Line Protection	-	0.4	0.4	-	-	-	-	-	0.4	100.0%	0.4	100.0%
55	58001	Edmonton-Calgary 500 kV East Route	-	-	-	-	-	0.4	0.4	-	(0.4)	-100.0%	(0.4)	-100.0%
56	58112	Central East Transfer Out	3.5	2.9	-	6.4	1.9	1.6	-	3.5	1.3	81.3%	-	0.0%
57	58005	Relocate / Reterminate 7L98 to Lanfine	-	-	-	-	-	0.1	0.1	-	(0.1)	-100.0%	(0.1)	-100.0%
58		Various Other Projects below $0.0 individually	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
59		**TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM**	8.5	13.3	(1.9)	23.7	4.5	16.6	12.6	8.5	(3.3)	-19.9%	(14.5)	-100.0%
60														
61		**DIRECT ASSIGNED PROJECTS - CUSTOMER**												
62	51090	Rainbow Lake Gas	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
63	51162	Blumenort - Windy Hills 144kV Transmission Line	-	-	-	-	1.5	(1.5)	-	-	1.5	-100.0%	-	0.0%
64	51440	Whitetail Peaking Station Interconnection	1.5	0.1	-	1.6	1.5	-	-	1.5	0.1	100.0%	-	0.0%
65	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
66	53034	Ksituan River 754S Capacity Upgrade	-	0.1	0.1	-	-	0.1	0.1	-	-	0.0%	-	0.0%
67	53441	Thornton DTS Increase	0.1	-	-	0.1	-	0.1	-	0.1	(0.1)	-100.0%	-	0.0%
68	53455	M.D. Greenview Load	3.2	0.9	-	4.1	0.8	2.4	-	3.2	(1.5)	-62.5%	-	0.0%
69	53475	ATCO Woodlands Area Load	-	-	-	-	0.2	(0.2)	-	-	0.2	-100.0%	-	0.0%
70	53593	Grande Prairie	7.7	0.5	-	8.2	6.9	0.8	-	7.7	(0.3)	-37.5%	-	0.0%
71	54951	HR Milner 1 & 2 Gas	-	1.0	1.0	-					1.0	100.0%	1.0	100.0%
72	55119	Generator Capacity Increase	3.6	26.8	-	30.4	1.0	2.6	-	3.6	24.2	100.0%	-	0.0%
73	55605	Line Tap	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
74	55753	Merritt Sub and Line	-	-	-	-	0.3	(0.3)	-	-	0.3	-100.0%	-	0.0%
75	56727	Cold Lake Area Cogen	0.2	0.3	-	0.5	0.2	-	-	0.2	0.3	100.0%	-	0.0%
76	56778	Midstream New POD	0.4	-	-	0.4	-	0.4	-	0.4	(0.4)	-100.0%	-	0.0%
77	56779	Wolf Midstream	-	0.3	-	0.3					0.3	100.0%	-	0.0%
78	56810	Grizzly Bear Wind Facility Connection	2.8	2.0	-	4.8	2.3	0.5	-	2.8	1.5	100.0%	-	0.0%
79	56815	Paintearth Wind Project	0.9	0.1	-	1.0	0.8	0.1	-	0.9	-	0.0%	-	0.0%
80	56820	Halkirk II Wind Power Facility	-	-	-	-	0.5	(0.5)	-	-	0.5	-100.0%	-	0.0%
81	56831	RESC Big Sky MPC Solar	-	0.1	-	0.1					0.1	100.0%	-	0.0%
82	56865	Wainwright	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
83	56893	Foster Creek decommissioning	-	0.1	-	0.1					0.1	100.0%	-	0.0%
84	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.3	0.1	-	0.4	(0.1)	-100.0%	-	0.0%
85	58215	Sharp Hills Windfarm	5.3	0.8	-	6.1	4.8	0.5	-	5.3	0.3	60.0%	-	0.0%
86	58225	Garden Plain Wind	0.4	0.5	-	0.9	0.3	0.1	-	0.4	0.4	100.0%	-	0.0%
87	58515	Joss Jenner WAGF - Phase 2	-	0.1	-	0.1					0.1	100.0%	-	0.0%
88	58526	Oyen Wind Power Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
89	58564	BER Hand Hills MPC Wind	0.1	0.2	-	0.3	-	0.1	-	0.1	0.1	100.0%	-	0.0%
90	58562	Hand Hills Wind Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
91	58574	Forestberg Area Solar	-	-	-	-	0.1	(0.1)	-	-	0.1	-100.0%	-	0.0%
92	58578	Hand Hills WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
93	58843	Wheatland Wind New POS	0.6	0.4	-	1.0	0.5	0.1	-	0.6	0.3	100.0%	-	0.0%
94	58844	Echo Wind Power New POS	0.9	2.4	-	3.3	0.5	0.4	-	0.9	2.0	100.0%	-	0.0%
95	58922	Eyre 558S Substation Interconnection	0.4	(0.4)	-	(0.0)	0.3	0.1	-	0.4	(0.5)	-100.0%	-	0.0%
96	58923	Currant Lake Substation	6.4	(6.4)	-	-	4.7	1.7	-	6.4	(8.1)	-100.0%	-	0.0%
97	58924	Armitage Substation	7.2	(7.2)	-	-	5.5	1.7	-	7.2	(8.9)	-100.0%	-	0.0%
98	58925	Cavendish Substation	-	0.2	0.2	-	6.2	4.7	10.9	-	(4.5)	-95.7%	(10.7)	-98.2%
99	58965	Heartland Pump Station	0.7	(0.7)	-	-	0.5	0.2	-	0.7	(0.9)	-100.0%	-	0.0%
100		Various Other Projects below $0.0 individually	-	-	-	-	0.3	-	0.3	-	-	0.0%	(0.3)	-100.0%
101		**TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER**	43.2	22.1	1.3	64.0	40.5	14.0	11.3	43.2	8.1	57.9%	(10.0)	-88.5%
102														
103														
104		**TOTAL DIRECT ASSIGNED**	51.7	35.4	(0.6)	87.7	45.0	30.6	23.9	51.7	4.8	15.7%	(24.5)	-100.0%
105														
106		Total Transmission	145.3	150.2	136.7	158.8	95.5	160.2	110.4	145.3	(10.0)	-6.2%	26.3	23.8%
107														

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL EXPENDITURES & ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
108		**DIRECT GENERAL PP&E**												
109		Tools and Instruments	0.3	2.9	2.6	0.6	0.5	1.7	1.9	0.3	1.2	70.6%	0.7	36.8%
110		Transmission Asset Mgmt. Program	-	0.1	0.1	-	-	0.4	0.4	-	(0.3)	-75.0%	(0.3)	-75.0%
111		Transportation Equipment	3.2	4.4	4.6	3.0	3.8	5.4	6.0	3.2	(1.0)	-18.5%	(1.4)	-23.3%
112			3.5	7.4	7.3	3.6	4.3	7.5	8.3	3.5	(0.1)	-1.3%	(1.0)	-12.0%
113														
114		**SOFTWARE**	3.3	8.1	4.5	6.9	7.4	8.2	12.3	3.3	(0.1)	-1.2%	(7.8)	-63.4%
115			3.3	8.1	4.5	6.9	7.4	8.2	12.3	3.3	(0.1)	-1.2%	(7.8)	-63.4%
116		**BUILDINGS**												
117		Land, Buildings and Structures	0.1	1.2	1.0	0.3	0.5	0.4	0.8	0.1	0.8	100.0%	0.2	25.0%
118			0.1	1.2	1.0	0.3	0.5	0.4	0.8	0.1	0.8	100.0%	0.2	25.0%
119														
120			6.9	16.7	12.8	10.8	12.2	16.1	21.4	6.9	0.6	3.7%	(8.6)	-40.2%
121														
122		IT Common Matters Disallowance	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
123														
124		**Total Transmission Capital Additions**	152.2	166.9	149.5	169.6	107.7	176.3	131.8	152.2	(9.4)	-5.3%	17.7	13.4%
125		Net Salvage			(7.3)				(7.6)					
126		Additions to Property			142.2				124.2					

ATCO Electric Transmission (AET)
SUMMARY OF CAPITAL CONTRIBUTIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

			2021 Actual				2020 Actual							
Line No.	Project	Description	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	CWIP Balance	Cap Expend	Cap Adds	CWIP Balance	Higher/(Lower) Expenditures Actual to Actual	Var. %	Higher/(Lower) Additions Actual to Actual	Var. %
1	**DIRECT ASSIGNED PROJECTS**													
2	51074	Fort Nelson Remedial Action Scheme	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
3	51090	ATCO Power Rainbow Lake Gas	0.2	(0.2)	-	-	0.2	-	-	0.2	(0.2)	-100.0%	-	0.0%
4	51162	Blumenort - Windy Hill 144 kV Transmission Line	-	-	-	-	1.4	(1.4)	-	-	1.4	-100.0%	-	0.0%
5	51181	Three Creeks Power Plant	-	-	-	-	1.0	(1.0)	-	-	1.0	-100.0%	-	0.0%
6	51440	Whitetail Peaking Station Interconnection	1.6	-	-	1.6	1.6	-	-	1.6	-	0.0%	-	0.0%
7	51760	Fort Saskatchewan WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
8	53034	Ksituan River 754S Capacity Upgrade	-	-	-	-	-	(0.2)	(0.2)	-	0.2	-100.0%	0.2	-100.0%
9	53595	Grande Prairie MPC Gas	-	0.9	-	0.9	-	-	-	-	0.9	100.0%	-	0.0%
10	54315	Proctor and Gamble Substation Capacity Addition	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
11	54951	HR Milner 1 & 2 Gas	-	1.3	1.3	-	-	-	-	-	1.3	100.0%	1.3	100.0%
12	53324	STS Contract Capacity Increase	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
13	53440	Thornton New POD	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
14	54954	Generator Increase	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
15	54955	Milner 2 Expansion	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
16	55119	Generator Capacity Increase	6.6	48.7	-	55.3	1.6	5.0	-	6.6	43.7	874.0%	-	0.0%
17	55145	ATCO 9L32/66	0.7	(0.7)	-	-	0.2	0.5	-	0.7	(1.2)	-240.0%	-	0.0%
18	55579	FHEC Fort Hills Substation	-	0.4	0.4	-	-	-	-		0.4	100.0%	0.4	100.0%
19	55187	Service for MacKay SAGD	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
20	55584	Green Stocking Substation	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
21	55605	Line Tap	0.3	-	-	0.3	0.2	0.1	-	0.3	(0.1)	-100.0%	-	0.0%
22	55633	55633 Surmont II (Stages 3)	-	-	-	-	-	(0.1)	(0.1)	-	0.1	-100.0%	0.1	-100.0%
23	55680	55680 Hangingstone SAGD	-	-	-	-	-	0.2	0.2	-	(0.2)	-100.0%	(0.2)	-100.0%
24	55709	CNRL Kirby North	-	-	-	-	0.1	-	0.1	-	-	0.0%	(0.1)	-100.0%
25	55735	Germain Substation and 144kV Line	-	-	-	-	-	3.7	3.7	-	(3.7)	-100.0%	(3.7)	-100.0%
26	56727	Pengrowth Cold Lake Area Cogen	0.6	-	-	0.6	0.6	-	-	0.6	-	0.0%	-	0.0%
27	56810	Grizzly Bear Wind Power Facility	2.2	4.1	-	6.3	2.1	0.1	-	2.2	4.0	4000.0%	-	0.0%
28	56815	Paintearth Wind Project	0.7	0.4	-	1.1	0.7	-	-	0.7	0.4	100.0%	-	0.0%
29	56820	Halkirk II Wind Power Facility	-	-	-	-	0.8	(0.8)	-	-	0.8	-100.0%	-	0.0%
30	56831	RESC Big Sky MPC Solar	-	0.5	-	0.5	-	-	-		0.5	100.0%	-	0.0%
31	56865	Wainwright	-	-	-	-	0.2	(0.2)	-	-	0.2	-100.0%	-	0.0%
32	56995	Northland Buffalo Trail WAGF	-	0.6	-	0.6	-	-	-		0.6	100.0%	-	0.0%
33	56878	SAGD Foster Creek DTS Cap Upgrade	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
34	58145	Red Deer Battery Energy Storage System	0.4	-	-	0.4	0.4	-	-	0.4	-	0.0%	-	0.0%
35	58204	Battery Storage	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
36	58215	Wind Farm New Facility Generator Capacity	12.9	-	-	12.9	12.8	0.1	-	12.9	(0.1)	-100.0%	-	0.0%
37	58225	Garden Plain Wind	0.4	2.6	-	3.0	0.3	0.1	-	0.4	2.5	2500.0%	-	0.0%
38	58515	Joss Jenner WAGF - Phase 2	0.2	0.4	-	0.6	-	0.2	-	0.2	0.2	100.0%	-	0.0%
39	58525	Oyen Wind Energy Project	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
40	58526	Oyen Wind Power Project	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
41	58562	Hand Hills Wind Power Facility - 58562	-	-	-	-	0.7	(0.7)	-	-	0.7	-100.0%	-	0.0%
42	58564	BER Hand Hills MPC Wind	0.2	1.7	-	1.9	-	0.2	-	0.2	1.5	750.0%	-	0.0%
43	58569	Hand Hills Wind Power Facility	-	-	-	-	1.0	(1.0)	-	-	1.0	-100.0%	-	0.0%
44	58570	BluEarth Bindloss MPC Solar Battery	-	0.1	-	0.1								
45	58572	Hand Hills Wind Project Phase 2	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
46	58573	Hand Hills Solar	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
47	58574	Forestberg Area Solar	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
48	58578	Hand Hills WAGF	0.1	-	-	0.1	0.1	-	-	0.1	-	0.0%	-	0.0%
49	58843	Wheatland Wind New POS	0.5	2.1	-	2.6	0.5	-	-	0.5	2.1	100.0%	-	0.0%
50	58844	Echo Wind Power New POS	1.2	8.7	-	9.9	1.2	-	-	1.2	8.7	100.0%	-	0.0%
51	58922	Eyre 558S Substation Interconnection	0.1	(0.1)	-	-	0.1	-	-	0.1	(0.1)	-100.0%	-	0.0%
52	58925	Cavendish Substation	-	(2.1)	(2.1)	-	1.0	4.4	5.4	-	(6.5)	-147.7%	(7.5)	-138.9%
53		Rounding	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
54			29.3	69.2	(0.4)	98.9	29.2	9.1	9.0	29.3	60.1	660.4%	(9.4)	200.0%
55	**OTHER TRANSMISSION**													
56	50463	Kearl 9L101	-	-	-	-	19.0	(19.0)	-	-	19.0	-100.0%	-	0.0%
57	50020	Transmission Capital Maintenance - Lines	0.1	0.2	0.2	0.1	-	0.2	0.1	0.1	-	0.0%	0.1	100.0%
58	50010	Transmission Capital Maintenance - Substations	0.1	0.3	0.4	-	0.6	-	0.5	0.1	0.3	100.0%	(0.1)	-20.0%
59		Telecom Capital Maintenance - General	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
60		Rounding				-				-	-	0.0%	-	0.0%
61			0.2	0.5	0.6	0.1	19.6	(18.8)	0.6	0.2	19.3	-102.7%	-	0.0%
62														
63			29.5	69.7	0.2	99.0	48.8	(9.7)	9.6	29.5				

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Expend	2020 Actual Expend	Variance	Var %	Variance Explanation
1	TOTAL CAPITAL MAINTENANCE		88.6	97.6	(9.0)	-9.2%	2021 expenditures are lower than prior year mainly due to Kearl 9L101 being executed in 2020 with completion in early 2021.
2	TOTAL TELECOMMUNICATION		12.7	14.4	(1.7)	-11.8%	2021 expenditures are lower than prior year mainly due to Network Multiplexor Upgrade project being substantially completed in 2020 and lower expenditures in Telecommunication Capital Maintenance and Replacement of End of Life Radios programs due to project schedule adjustments, offset by higher costs in Telecom Tower Replacements mainly due to completion of 950S Germain substation to TELUS tower facility at Chipewyan Lake fiber addition project in 2021.
3	TOTAL TRANSMISSION ISOLATED GENERATION		11.4	15.2	(3.8)	-25.0%	2021 expenditures are lower than prior year mainly due to more Alternate Power Supply/Renewable projects being in execution stage in 2020.
4	TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM		13.3	16.6	(3.3)	-19.9%	2021 capital expenditures were lower than prior year mainly due to fewer active system projects. 2020 Capital Expenditures included trailing costs for both 55737 Thickwood Development and 54904 Jasper Transmission Interconnection, which were completed in 2020. This is partially offset by higher costs in 2021 for 53043 Rycroft due to initial static VAR system (SVS) payments and detailed design activity, as well as a credit in expenditures in 54904 Jasper Transmission Interconnection related to the reversal of the accrual of shared costs of existing facilities payment after the AESO deemed that AML owed the funds and not AET.
5	TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER		22.1	14.0	8.1	57.9%	2021 capital expenditures were higher than prior year mainly due to the procurement of equipment and engineering costs in 55119 Suncor Generator Capacity Addition, partially offset by the cancellation of 58923 Currant Lake Substation and 58924 Armitage Substation.

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CAPITAL ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Adds	2020 Actual Adds	Variance	Var %	Variance Explanation
1		TOTAL CAPITAL MAINTENANCE	98.7	64.3	34.4	53.5%	2021 additions are higher than prior year mainly due to the completion of Kearl 9L101, 757S Battle River substation emergency transformer replacement, and line to ground clearance projects.
2		TOTAL TELECOMMUNICATION	16.0	12.9	3.1	24.0%	2021 additions are higher than prior year mainly due to completion of projects in the Telecommunication Capital Maintenance and Telecom Tower Replacements programs, offset by lower additions in Network Multiplexor Upgrade project being substantially completed in 2020 and schedule adjustments in Replacement of End of Life Radios.
3		TOTAL TRANSMISSION ISOLATED GENERATION	20.7	6.9	13.8	200.0%	2021 additions are higher than prior year mainly due to completing Alternate Power Supply/Renewables projects in 2020 for Chipewyan Lake Interconnection and Fort Chipewyan Renewable Energy Solution.
4		TOTAL DIRECT ASSIGNED PROJECTS - SYSTEM	(1.9)	12.6	(14.5)	-115.1%	2021 additions were lower than prior year mainly due to trailing costs for 55737 Thickwood Development and 54904 Jasper Transmission Interconnection being significantly completed in 2020. The credit balance in additions is due to the reversal of the accrual for the shared use of existing facilities payment in 54904 Jasper Transmission Interconnection, after the AESO determined that AML owed the funds and not AET.
5		TOTAL DIRECT ASSIGNED PROJECTS - CUSTOMER	1.3	11.3	(10.0)	-88.5%	2021 capital additions were lower than prior year mainly due to the energization of 58925 Cavendish Substation occurring in 2020. There were no large projects energized in 2021.
6		TOTAL SOFTWARE	4.5	12.3	(7.8)	-63.4%	Actual capital additions were lower in 2021 compared to prior year primarily related to the completion of a portion of the Asset Management program in 2020.

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Expend	2020 Actual Expend	Variance	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	51162	Blumenort - Windy Hills 144kV Transmission Line	-	(1.4)	1.4	-100.0%	2021 Actuals are higher than prior year due to refund issued in 2020 when the project was cancelled.
3	55119	Generator Capacity Increase	48.7	5.0	43.7	874.0%	2021 Actuals are higher than prior year due to progressing from the design phase into the construction phase of the project.
4	55145	ATCO 9L32/66	(0.7)	0.5	(1.2)	-240.0%	2021 Actuals are lower than prior year due to the ATCO 9L32/66 line move project being deemed a system project which was approved in AUC Decision 24964-D02-2021 and AUC Decision 26708-D01-2021. As a result of these decisions, the contribution previously received was refunded to the customer.
5	55735	Germain Substation and 144kV Line	-	3.7	(3.7)	-100.0%	2021 Actuals are lower than prior year due to a customer requested decrease to the existing DTS rate capacity contract which resulted in additional contributions being required in 2020.
6	56810	Grizzly Bear Wind Power Facility	4.1	0.1			2021 Actuals are higher than prior year due to the project moving into the construction phase.
7	58225	Garden Plain Wind	2.6	0.1			2021 Actuals are higher than prior year due to the project moving into the construction phase.
8	58564	BER Hand Hills MPC Wind	1.7	0.2			2021 Actuals are higher than prior year due to the project moving into the construction phase.
9	58843	Wheatland Wind New POS	2.1	-			2021 Actuals are higher than prior year due to the project moving into the construction phase.
10	58844	Echo Wind Power New POS	8.7	-	8.7	0.0%	2021 Actuals are higher than prior year due to the project moving into the construction phase.
11	58925	Cavendish Substation	(2.1)	4.4	(6.5)	-147.7%	2021 Actuals are lower than prior year due to final project costs coming in lower than originally forecast, resulting in a partial contribution refund to customer.
12	54951	HR Milner 1 & 2 Gas	1.3	-			2021 Actuals are higher than prior year due to the project moving into the construction phase.
13	**TOTAL DIRECT ASSIGNED PROJECTS**		**66.4**	**12.6**	**42.4**		
14							
15	**OTHER TRANSMISSION**						
16		Kearl 9L101	-	(19.0)	19.0	-100.0%	2021 Actuals are higher than prior year due to the 9L101 Kearl line relocation costs being deemed system in 2020 rather than customer per AUC Decision 25282- D01-2020. As a result of the decision, the contribution previously received was refunded to the customer.
17	**OTHER TRANSMISSION TOTAL**		**0.0**	**(19.0)**	**19.0**		

ATCO Electric Transmission (AET)
VARIANCE EXPLANATIONS OF CONTRIBUTION ADDITIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Project	Description	2021 Actual Adds	2020 Actual Adds	Variance	Var %	Variance Explanation
1	**DIRECT ASSIGNED PROJECTS**						
2	55735	Germain Substation and 144kV Line	0.0	3.7	(3.7)	-100.0%	2021 Actuals are lower than prior year due to a customer requested decrease to the existing DTS rate capacity contract in 2020 which resulted in additional contribution.
3	58925	Cavendish Substation	(2.1)	5.4	(7.5)	-138.9%	2021 Actuals are lower than prior year due to final project costs coming in lower than originally forecast resulting in a partial contribution refund to customer.
4	54951	HR Milner 1 & 2 Gas	1.3	0.0	1.3	0.0%	2021 Actuals are higher than prior year due to project completion in 2021.
5	**TOTAL DIRECT ASSIGNED PROJECTS**		**(0.8)**	**9.1**	**(9.9)**		

ATCO Electric Transmission (AET)
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Net Income Before Tax		203.0	203.1	(0.1)	0%	
2	Total Federal Permanent Differences		(4.2)	(4.7)	0.5	-11%	
3	Total Federal Timing Differences		(148.4)	(150.3)	1.9	-1%	
4	Total Federal Differences		(152.6)	(155.0)	2.4	-2%	
5	Total Provincial Permanent Differences		(4.2)	(4.7)	0.5	-11%	
6	Total Provincial Timing Differences		(148.3)	(150.3)	2.0	-1%	
7	Total Provincial Differences		(152.5)	(155.0)	2.5	-2%	
8	Federal Income Tax Rate		15%	15%			
9	**Total Federal Income Tax**		**7.6**	**7.2**	0.4	5%	
10							
11	Provincial Income Tax Rate		8%	9%			
12	**Total Provincial Income Tax**		**4.0**	**4.3**	(0.3)	-7%	
13							
14	**Current Tax Payable**						
15	Large Corporation and Other Tax			-			
16	Prior Year (over)/under provisions		-	(2.1)	2.1	-100%	
17	Current Year (over)/under provisions			-			
18	Other		1.3	1.5	(0.2)	-12%	
19	Current Income Tax		12.9	10.9	1.9	18%	
20	Deferred Tax- Future Income Tax		22.3	22.5	(0.3)	-1%	
21	**Corporate Income Tax**		35.1	33.5	1.7	5%	
22							
23	**Income Tax Adjustments**						
24	Tax on disallowed O&M		-	-	-	-	
25	Other		-	-	-	-	
26							
27	Utility Income Tax						
28	Effect of Normalization		-	-	-	0%	
29	**Utility Income Tax**		**35.1**	**33.5**	1.7	5.0%	

ATCO Electric Transmission (AET)
EXPLANATION OF TRANSACTIONS WITH AFFILIATED COMPANIES
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Service	Cross-Reference	Affiliate	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	**Transmission Affiliate Cost of Goods Sold**							
2	Operations & Maintenance		Alberta PowerLine	-	-	-	100.0%	
3	Engineering and Project Services		ATCO Power Canada Ltd.	-	-	-	100.0%	
4	Project and Asset Management Services		ATCO Energy Solutions Ltd.	0.3	0.2	0.1	31.3%	
5	Project and Asset Management Services		ATCO Power 2010 Ltd.	6.3	10.9	(4.6)	-42.0%	**Note 1**
6	Procurement and Supply Chain Management Services		ATCO Pipelines	0.1	-	0.1	100.0%	
7	Project Services		ATCO Pipelines	0.1	-	0.1	100.0%	
8	Tower and Circuit Leases		ATCO Gas	0.1	0.1	-	0.0%	
9	Project Services		ATCO Gas	0.1	-	0.1	100.0%	
10	Project Services		Ashcor	-	0.1	(0.1)	-100.0%	
11	Project Services		ATCO Infrastructure Solutions Ltd.	0.8	2.3	(1.5)	-64.6%	**Note 2**
12				7.8	13.6	(5.8)	-42.8%	
13	**Isolated Generation Affiliate Cost of Goods Sold**							
14	Other items individually less than $0.1			-	0.0	(0.0)	-100.0%	
15				-	0.0	(0.0)		
16	**Corporate Affiliate Cost of Goods Sold**							
17	Administrative Services		Alberta PowerLine	-	-	-	100.0%	
18	Administrative Services		Northland Utilities (NWT) Limited	1.0	0.5	0.5	94.8%	
19	Administrative Services		Yukon Electrical Company Limited	0.1	0.1	(0.0)	-13.5%	
20	Administrative Services		Northland Utilities (Yellowknife) Limited	0.0	0.1	(0.1)	-91.1%	
21				1.1	0.7	0.4	58.3%	
22								
23	**Total Affiliate Cost of Goods Sold**			**8.8**	**14.2**	**(5.4)**	-38.0%	
24								
25								
26	**Note 1:** 2021 Actuals affiliate cost of goods sold was lower than prior year due to project completion and lower project services required in 2021.							
27	**Note 2:** 2021 Actuals affiliate cost of goods sold was lower than prior year due to higher project services costs in 2020.							

ATCO Electric Transmission (AET)
SUMMARY OF PAYROLL AND MANPOWER STATISTICS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

SALARIES, WAGES AND EMPLOYEE BENEFITS

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
1	Salaries, Wages and Employee Benefits						
2	Transmission Operations		23.8	26.7	(2.8)	-10.6%	**Note 1**
3	Transmission Capital		49.8	50.5	(0.7)	-1.4%	
4	Transmission Corporate - Operations		9.7	10.5	(0.8)	-7.8%	
5	Transmission Corporate - Capital		6.0	6.1	(0.1)	-1.4%	
6							
7	**Salaries, Wages and Employee Benefits Charged to Utility Operations**		89.3	93.7	(4.5)	-4.8%	

EMPLOYEE ALLOCATION

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Var. Actual to Prior Year	Var. %	Working Paper Reference
8	Manpower Statistics						
9	Total Regular Employees (FTEs)		535.1	557.1	(22.1)	-4.0%	
10	Total Temporary Employees (FTEs)		25.1	18.4	6.7	36.5%	
11	**Total Manpower**		560.2	575.5	(15.3)	-2.7%	
12	Less:						
13	Allocated to Non-regulated		-	-			
14	**Total Manpower - Utility Operations**		560.2	575.5			
15							

16 **Variance Explanations**

17

18 **Note 1:** Salaries, Wages, and Employee Benefits are lower than prior year due to decreased workload requirements primarily related to maintenance activities.

ATCO Electric Transmission (AET)
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.	Description	Cross-Ref.	2021 Actual Opening Balance	Adds	Provision	Adjustments	Ending Balance	Working Paper Reference
1	List of Reserve/Deferral Accounts							
2								
3	Reserve for Injuries and Damages		(0.2)	-	0.8	-	0.6	
4	Variable Pay Program (VPP)		4.3	(4.2)	4.4	-	4.4	
5	Vegetation Management		(0.1)	(5.2)	5.2	-	(0.1)	
6								
7	**Total Deferred Assets**		4.0	(9.4)	10.4	-	4.9	
8								
9	Federal Future Income Tax		238.2	5.8	24.0	-	268.0	
10								
11	**Total Deferred Liabilities**		238.2	5.8	24.0	-	268.0	

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
1	**Revenues**		**1,231.0**	**(442.7)**	**941.0**	**732.7**		
2								
3	Impact of AUC Decisions						4.7	
4	Eliminate Non-Utility Revenues						(5.3)	
5	Adjustment of Customer Contribution for KXL Cancelled Project						(13.5)	
6	Reclassification of Revenue Offsets						(20.3)	
7	Reclass of Amortization of Contributions to Depreciation						(10.7)	
8	Non IFRS Deferral Revenue						(3.3)	
9	Other						2.2	
10								
11		Sch 1.0-T	1,231.0	(442.7)	941.0	732.7	(46.3)	**686.4**
12								
13	**Cost of Sales**		**-**	**(433.1)**	**433.1**	**-**		
14								
15								
16			-	(433.1)	433.1	-	-	**-**
17								
18	**Fuel**		**3.1**	**-**	**0.0**	**3.1**		
19								
20								
21		Sch 1.0-T	3.1	-	0.0	3.1	-	**3.1**
22								
23								
24	**Operating and Maintenance**		**441.7**	**0.9**	**224.0**	**216.8**		
25								
26	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						(9.8)	
27	Non-recovered (Disallowed) Utility Costs						(5.8)	
28	AUC Enforcement - Penalty						(31.0)	
29	AUC Enforcement - Write-Off of Capital Project Costs						(10.8)	
30	AUC Enforcement - Legal/Other						(1.2)	
31	Farms Reclassification						(4.6)	
32	Reclassification of Other Cancelled Projects from Depreciation						1.5	
33	Reclassification of Credit Facility fees from Financing						1.1	
34	Other						0.3	
35								
36		Sch 1.0-T	441.7	0.9	224.0	216.8	(60.3)	**156.5**
37								

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
38	**Depreciation and Amortization**		**311.6**	**(8.0)**	**134.1**	**185.5**		
39								
40	Negative Salvage (Net Dismantling Costs) Reclass to Depreciation						48.5	
41	Reclass of Amortization of Contributions to Depreciation						(10.7)	
42	Farms Reclassification						1.4	
43	Reclassification of Other Cancelled Projects to O&M						(1.5)	
44	Non-Utility Depreciation						(0.8)	
45	Depreciation Relating to AUC Enforcement - Capital Write-Off						(0.4)	
46	Impact of AUC Decisions						1.4	
47	Adjustment of KXL Cancelled Project Write-Off						(10.4)	
48	Other						(4.3)	
49								
50		Sch 1.0-T	311.6	(8.0)	134.1	185.5	23.3	**208.8**
51								
52	**Income Tax**		**65.0**	**(0.6)**	**17.9**	**47.7**		
53								
54	Tax on Adjustments	Note 2					(12.6)	
55								
56		Sch 1.0-T	65.0	(0.6)	17.9	47.7	(12.6)	**35.1**
57								
58	**Revenue Offsets**		**-**	**-**	**-**	**-**		
59								
60	Reclassification of Revenue Offsets						20.3	
61								
62		Sch 1.0-T	-	-	-	-	20.3	**20.3**
63								
64	**Return**		**409.5**	**(2.0)**	**132.0**	**279.5**		
65	Adjustments	Note 1					23.7	
66		Sch 1.0-T	409.5	(2.0)	132.0	279.5	23.7	**303.2**
67								
68	**Note 1 - Return Adjustments**							
69	Long Term Debt & Other		**218.8**	**-**	**66.6**	**152.2**		
70	Adjustment for IFRS IDC Treatment						(3.2)	
71	Credit facility Reclass to O&M						(1.1)	
72	Adjustment for KXL Cancelled Project						(3.1)	
73	Financing Other						(4.4)	
74			218.8	-	66.6	152.2	(11.8)	**140.4**
75								
76	Preferred Shares		**-**	**-**	**-**	**-**		
77							2.8	
78			-	-	-	-	2.8	**2.8**
79								
80	Return on Equity		**190.7**	**(2.0)**	**65.4**	**127.3**		
81		Note 2					32.6	
82			190.7	(2.0)	65.4	127.3	32.6	**159.9**
83								
84	**Total Return Adjustments**		**409.5**	**(2.0)**	**132.0**	**279.5**	**23.7**	**303.2**

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
(TRANSMISSION & DISTRIBUTION)
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Intercompany Eliminations	Distribution Financial Statements	Transmission Financial Statements	Transmission Utility Adjustments	Transmission Utility Total
85								
86							**(Return)**	
87	**Note 2 - Return on Equity Adjustments**					**Before tax**	**After tax**	**Tax impact**
88								
89	**Financing & Subs**							
90	Preferred Dividends					(2.8)	(2.8)	
91	IDC					6.3	4.9	**1.5**
92	Interest and Other					5.5	4.2	**1.3**
93								
94	**Income Tax**							
95	Income Tax (Provincial Future Tax for IFRS)						13.0	**(13.0)**
96	Income Tax (T2S1 Additions & Deductions Non Regulatory)						(0.3)	**0.3**
97	Income Tax (T2S1 Additions & Deductions Non IFRS)						(0.0)	**0.0**
98	Income Tax (Book to Filing)						(1.1)	**1.1**
99	Income Tax (T2S1 Other)						6.2	**(6.2)**
100								
101	**Other Income Statement Items**							
102	Revenue Tax Impact					(25.9)	(20.0)	**(6.0)**
103	O&M Tax Impact					60.3	46.4	**13.9**
104	Depreciation Tax Impact					(23.3)	(17.9)	**(5.4)**
105								
106						20.0	32.6	**(12.6)**

ATCO Electric Transmission (AET)

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS

(Transmission and Distribution)

FOR THE YEAR ENDED DECEMBER 31, 2021

BALANCE SHEET ITEMS

($Millions)

Line No.	Description	Cross-Reference	Audited Financial Statements	Adjustments	Total
1	**Assets**				
2	Current Assets				
3	Cash and short term investments		18.5	-	18.5
4	Accounts receivable		147.6	(0.4)	147.2
5	Income taxes		0.2	757.6	757.8
6	Inventories		3.8	-	3.8
7	Prepaid expenses		6.2	-	6.2
8					
9	Property, plant and equipment		9,853.7	(1,844.9)	8,009
10					
11	Investments		131.5	(16.5)	114.9
12					
13	Regulatory Assets		-	103.6	103.6
14	Deferred financing Charges		-	27.2	27.2
15	Other		-	-	-
16					
17	**Total Assets**		**10,161.4**	**(973.4)**	**9,188.0**
18					
19					
20	**Liabilities**				
21	Current Liabilities				
22	Bank Indebtedness		-	-	-
23	Short term advances from parent and affiliated corporations		57.7	-	57.7
24	Accounts payable and accrued liabilities		160.3	(0.6)	159.7
25	Owing to parent and affiliated corporations		72.7	-	72.7
26	Income taxes payable		0.0	0.0	0.0
27	Regulatory Liabilities		-	-	-
28	Long term debt		50.0	(50.0)	-
29					
30	Future income taxes		949.5	(5.8)	943.7
31	Regulatory Liabilities		-	-	-
32	Long term debt		5,006.3	(26.8)	4,979.5
33	Other		1,107.1	(1,041.4)	65.7
34					
35	**Total Liabilities**		**7,403.6**	**(1,124.6)**	**6,279.0**
36					
37	**Equity**				
38	Equity preferred shares to Parent Corporation		98.3	1.7	100.0
39					
40	Class A and Class B shares owner's equity				
41	Class A and Class B shares		1,212.4	-	1,212.4
42	Retained earnings		1,447.1	149.4	1,596.6
43	**Total Equity**		**2,757.9**	**151.1**	**2,909.0**
44					
45	**Total Liabilities and Share Owner's Equity**		**10,161.4**	**(973.4)**	**9,188.0**

ATCO Electric Transmission (AET)
Summary of Pension Plan Contributions
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

ATCO Electric has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

2021 Actual

	Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
	Service Amount	Special Payment	Service Amount	
ATCO Electric (Note 1)	1.3	-	3.6	**4.9**
ATCO Other	2.5	-	6.1	**8.6**

Note 1 - The actual defined benefit and defined contribution service amounts along with the special payment do not include amounts that are allocated from the ATCO Head office.
This amount includes COLA at 100%

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.
Accordingly the deferral account should be calculated as the annual difference between the amounts collected in rates in respect of the special payments and the special payment amounts actually paid by ATCO Utilities pursuant to the Pension Valuation(s) accepted by the Superintendent of Pensions that were in force during such year.

<u>2020 Reconciliation (ATCO Electric - Transmission)</u>

2020 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 2)	-
2020 Actual Special Payment Pension contributions	-
2020 Actual Special Payment Pension contributions - allocated from ATCO Head Office	-
Refund/(collection) to / (from) customers	-

Note 2 - Per ATCO Electric Transmission 2020-2022 GTA Compliance Filing (Exhibit 24964-X0003, Attachment 3, Schedule 3, Line 6

<u>2021 Reconciliation (ATCO Electric - Transmission)</u>

2021 Special Payment Pension costs included in ATCO Electric Transmission's Revenue Requirement (Note 3)	-
2021 Actual Special Payment Pension contributions	-
2021 Actual Special Payment Pension contributions - allocated from ATCO Head Office	-
Refund/(collection) to / (from) customers	-

Note 3 - Per ATCO Electric Transmission 2020-2022 GTA Post Disposition Filing (Exhibit 26477-X0010, Attachment 3, Schedule 3, Line 6
Pension information can be found per ATCO Electric Transmission's 2020-2022 GTA filing. Exhibit 24964-X0001, Section 1.6 - Deferral and Reserve Accounts - Defined Benefit Pension Plan Funding

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2020 CU Pension Plan Report dated August 11, 2021, was filed with the Superintendent of Pensions.

ATCO ELECTRIC LTD.

NON-CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021

Independent auditor's report

To the Shareowner of ATCO Electric Ltd.

Our opinion

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of ATCO Electric Ltd. (the Company) as at December 31, 2021 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Company's non-consolidated financial statements comprise:

- the non-consolidated statement of earnings for the year ended December 31, 2021;
- the non-consolidated statement of comprehensive income for the year ended December 31, 2021;
- the non-consolidated balance sheet as at December 31, 2021;
- the non-consolidated statement of changes in equity for the year ended December 31, 2021;
- the non-consolidated statement of cash flow for the year ended December 31, 2021; and
- the notes to the non-consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the non-consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the non-consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Stantec Tower, 10220 103 Avenue NW, Suite 2200, Edmonton, Alberta, Canada T5J 0K4
T: +1 780 441 6700, F: +1 780 441 6776

Responsibilities of management and those charged with governance for the non-consolidated financial statements

Management is responsible for the preparation and fair presentation of the non-consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of non-consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the non-consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the non-consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the non-consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these non-consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the non-consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the non-consolidated financial statements, including the disclosures, and whether the non-consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
April 29, 2022

TABLE OF CONTENTS

NON-CONSOLIDATED STATEMENT OF EARNINGS

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Revenues	4	**1,230,980**	1,217,919
Costs and expenses			
Salaries, wages and benefits		**(90,863)**	(92,471)
Plant and equipment maintenance		**(78,409)**	(77,179)
Fuel costs		**(3,137)**	(3,499)
Depreciation and amortization	8,9	**(311,608)**	(298,731)
Franchise fees		**(31,982)**	(30,194)
Property and other taxes		**(51,815)**	(50,810)
Other	5	**(188,610)**	(147,609)
		(756,424)	(700,493)
Dividend income from subsidiary companies	10	**8,480**	8,852
Operating profit		**483,036**	526,278
Interest income		**5,815**	5,442
Interest expense	6	**(233,089)**	(229,665)
Net finance costs		**(227,274)**	(224,223)
Earnings before income taxes		**255,762**	302,055
Income tax expense	7	**(65,048)**	(73,093)
Earnings for the year		**190,714**	228,962

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2021**	**2020**
Earnings for the year		**190,714**	228,962
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	12	**6,494**	(4,240)
Comprehensive income for the year		**197,208**	224,722

(1) Net of income taxes of $(2) million for the year ended December 31, 2021 (2020 - $1 million).

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2021	2020
ASSETS			
Current assets			
Cash		**15,467**	4,854
Short-term advances to parent company	23	**2,999**	29,000
Accounts receivable and contract assets	13	**144,274**	135,538
Accounts receivable from parent and affiliate companies	13, 23	**3,306**	5,091
Inventories		**3,795**	4,161
Income taxes recoverable		**167**	719
Prepaid expenses and other current assets		**6,224**	6,281
		176,232	185,644
Non-current assets			
Property, plant and equipment	8	**9,498,386**	9,489,268
Intangibles	9	**355,313**	330,535
Investment in subsidiary companies	10	**16,335**	16,335
Long-term advances to subsidiary companies	23	**104,023**	104,023
Other assets		**11,113**	11,735
Total assets		**10,161,402**	10,137,540
LIABILITIES			
Current liabilities			
Bank indebtedness		**3,021**	–
Short-term advances from parent and affiliated companies	23	**54,700**	109,000
Accounts payable and accrued liabilities		**101,003**	100,020
Accounts payable to parent and affiliate companies	23	**72,670**	57,340
Long-term debt	11, 23	**50,010**	101,000
Provisions and other current liabilities		**59,287**	28,216
		340,691	395,576
Non-current liabilities			
Deferred income tax liabilities	7	**949,465**	885,477
Retirement benefit obligations	12	**59,127**	67,267
Customer contributions	13	**1,046,609**	980,874
Long-term debt	11, 23	**5,006,263**	4,895,922
Other liabilities		**1,396**	1,080
Total liabilities		**7,403,551**	7,226,196
EQUITY			
Equity preferred shares	14, 23	**98,280**	141,968
Class A and Class B share owner's equity			
Class A and Class B shares	15	**1,212,428**	1,212,428
Retained earnings		**1,447,143**	1,556,948
		2,659,571	2,769,376
Total equity		**2,757,851**	2,911,344
Total liabilities and equity		**10,161,402**	10,137,540

See accompanying Notes to Non-consolidated Financial Statements.

DIRECTOR

DIRECTOR

NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
December 31, 2019		1,212,428	141,968	1,652,117	–	3,006,513
Earnings for the year		–	–	228,962	–	228,962
Other comprehensive loss		–	–	–	(4,240)	(4,240)
Loss on retirement benefits transferred to retained earnings	12	–	–	(4,240)	4,240	–
Dividends	14,15	–	–	(319,891)	–	(319,891)
December 31, 2020		1,212,428	141,968	1,556,948	–	2,911,344
Earnings for the year		–	–	**190,714**	–	**190,714**
Other comprehensive loss		–	–	–	**6,494**	**6,494**
Gain on retirement benefits transferred to retained earnings	12	–	–	**6,494**	**(6,494)**	–
Redemption of equity preferred shares	14	–	**(43,688)**	**(26)**	–	**(43,714)**
Dividends	14,15	–	–	**(306,987)**	–	**(306,987)**
December 31, 2021		**1,212,428**	**98,280**	**1,447,143**	–	**2,757,851**

See accompanying Notes to Non-consolidated Financial Statements.

NON-CONSOLIDATED STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Operating activities			
Earnings for the year		**190,714**	228,962
Adjustments to reconcile earnings to cash flows from operating activities	16	**650,246**	606,738
Changes in non-cash working capital	16	**59,379**	(8,169)
Cash flows from operating activities		**900,339**	827,531
Investing activities			
Additions to property, plant and equipment	8	**(281,872)**	(309,636)
Proceeds on disposal of property, plant and equipment		**242**	–
Additions to intangibles	9	**(48,943)**	(36,725)
Issue of long-term advances to subsidiary companies		**–**	(4,200)
Repayment of long-term advances to subsidiary companies		**–**	1,500
Changes in non-cash working capital	16	**(19,530)**	(14,832)
Other		**1,069**	651
Cash flows used in investing activities		**(349,034)**	(363,242)
Financing activities			
Issue of long-term debt	11	**160,600**	25,625
Repayment of long-term debt		**(101,000)**	(38,243)
Repayment of lease liability		**(327)**	(319)
Redemption of equity preferred shares to parent company	14	**(43,714)**	–
Dividends paid on equity preferred shares		**(4,985)**	(5,692)
Dividends paid to Class A and Class B share owner		**(302,002)**	(314,199)
Interest paid		**(222,432)**	(226,281)
Other		**(1,554)**	(498)
Cash flows used in financing activities		**(515,414)**	(559,607)
Increase (decrease) in cash position		**35,891**	(95,318)
Beginning of year		**(75,146)**	20,172
End of year	16	**(39,255)**	(75,146)

See accompanying Notes to Non-consolidated Financial Statements.

NOTES TO NON-CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2021

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

ATCO Electric is engaged in the transmission and distribution of electric energy in the Province of Alberta. Its registered office and head office is at 19th Floor, 10035 -105 Street NW, Edmonton, Alberta, T5J 2V6. ATCO Electric is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these non-consolidated financial statements, "the Company" means ATCO Electric Ltd.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The non-consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Pursuant to the Company's regulatory obligation to the Alberta Utilities Commission (AUC) and interested parties, the Company is obliged to provide detailed information relating solely to the electric utility and not relating to non-regulated subsidiaries, nor electric utilities regulated by other jurisdictions. The Company has, therefore, exercised the exemption from full consolidation of its investment in subsidiary companies available under IAS 27 *Separate Financial Statements*. As a result, the Company’s investment in subsidiary companies and joint arrangements are carried at the original cost and the earnings of the subsidiary companies are reflected in the determination of earnings of the Company only to the extent of dividends received from the subsidiaries. The Company's proportionate interest in balances and transactions of joint arrangements have been excluded from these non-consolidated financial statements. Consolidated financial statements of the Company’s immediate parent, CU Inc., that comply with IFRS are available for public use. CU Inc. is incorporated in Canada and its registered office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4.

Management authorized these non-consolidated financial statements for issue on April 29, 2022.

BASIS OF MEASUREMENT

The non-consolidated financial statements are prepared on a historic cost basis, except for retirement benefit obligations which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 24.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The non-consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the non-consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Estimates and judgments are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 20.

ADOPTION OF NEW ACCOUNTING INTERPRETATION

In April 2021, the IFRS Interpretations Committee published a final agenda decision with respect to recognition of certain configuration and customization expenditures related to cloud computing with retrospective application. Costs that do not meet the capitalization criteria should be expensed as incurred. Any changes resulting from the decision were required to be implemented by December 31, 2021.

As a result of the review of the impact of the decision on the financial statements, the Company recorded a decrease to intangible assets of $1.8 million with a corresponding increase to other expenses in the statement of earnings (Note 9).

3. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares,
- one-time gains and losses,
- impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of earnings used by the Chief Operating Decision Maker (CODM) to assess performance and allocate resources. Other accounts in the non-consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

	2021	2020
Adjusted earnings	**302,910**	304,577
Transition of managed IT services	**(13,657)**	(21,533)
AUC enforcement proceeding	**(41,133)**	–
Restructuring costs	**(756)**	(3,493)
Rate-regulated activities	**(53,456)**	(45,204)
IT Common Matters decision	**(8,179)**	(11,077)
Dividends on equity preferred shares	**4,985**	5,692
Earnings for the year	**190,714**	228,962

Transition of managed IT services

In 2020, Canadian Utilities Limited, signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) (subsequently novated to Kyndryl Canada Ltd.) to provide managed information technology (IT) services. These services were previously provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring December 2024. The transition of the managed IT services from Wipro to IBM commenced February 1, 2021 and was complete at December 31, 2021. In addition, the Company recognized transition costs of $18 million ($14 million after-tax) in 2021. The transition costs related to activities to transfer the managed IT services from Wipro to IBM. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

In 2020, the Company recognized an onerous contract provision of $28 million ($22 million after-tax), which represents management's best estimate of the costs to exit the Wipro MSA. The provision is included in provisions and other current liabilities in the non-consolidated balance sheets. The onerous contract provision is not in the normal course of business and has been excluded from adjusted earnings.

Alberta Utilities Commission (AUC) enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $41 million (after-tax) due to the potential outcome of the proceeding. As this proceeding is not in the normal course of business, these costs have been excluded from adjusted earnings.

Restructuring costs

In 2021, the Company recorded restructuring costs of $0.7 million, after-tax, that were not in the normal course of business. These costs mainly related to staff reductions and associated severance costs (2020 - $3.5 million).

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the Company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company recognizes revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2021	2020
Additional revenues billed in current period		
Future removal and site restoration costs [(1)]	**32,683**	26,815
Revenues to be billed in future periods		
Deferred income taxes [(2)]	**(49,211)**	(52,211)
Distribution rate relief [(3)]	**(48,232)**	–
Regulatory decisions received	**13,358**	8,610
Settlement of regulatory decisions and other items [(4)]	**(2,054)**	(28,418)
	(53,456)	(45,204)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by the Company.

(3) In 2021, in response to the ongoing COVID-19 Pandemic, ATCO Electric Distribution applied for interim rate relief for customers to hold current distribution base rates in place. Following approval by the AUC, ATCO Electric Distribution recorded a decrease in earnings of $48 million. This will be recovered from customers in 2022 and 2023.

(4) In 2020, ATCO Electric Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. The significant regulatory decisions impacting adjusted earnings during 2021 are provided below.

	Decision	Amount	Description
1.	2020-2022 ATCO Electric General Tariff Application (GTA) Compliance Decision	**6,296**	In October 2019, the Company filed a GTA for its Electric Transmission operations for 2020, 2021, and 2022. On April 19, 2021, the AUC issued its Compliance decision related to the 2020-2022 GTA resulting in a reduction in adjusted earnings of $6.3 million recorded in 2021.
2	2018-2019 ATCO Electric General Tariff Application (GTA) Compliance Decision	**7,062**	In June 2017, the Company filed a GTA for its Electric Transmission operations for 2018 and 2019. On August 12, 2020, the AUC issued its Compliance decision related to the 2018-2019 GTA resulting in a reduction in adjusted earnings of $7.1 million recorded in 2021.

The significant regulatory decisions impacting adjusted earnings during 2020 are provided below.

	Decision	Amount	Description
1.	ATCO Electric Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances	5,721	In March 2019, Electric Transmission filed an application seeking the approval of approximately $2.2 billion of capital additions from transmission projects with in-service dates between 2015-2017. In November 2020, Electricity Transmission received a decision regarding its 2019 application for the disposal of its 2015-2017 transmission deferral accounts and annual filing adjustment balances. The reduction in adjusted earnings resulting from the decision was $5.7 million, which relates to the period January 1, 2015 to December 31, 2017.
2.	2018-2019 ATCO Electric General Tariff Application (GTA) Compliance Decision	2,889	In June 2017, the Company filed a GTA for its Electric Transmission operations for 2018 and 2019. On August 12, 2020, the AUC issued its Compliance decision related to the 2018-2019 GTA resulting in a reduction in adjusted earnings of $2.9 million recorded in 2020.

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by CU Inc.'s parent, Canadian Utilities Limited, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2021 was $8.2 million (2020 - $11.1 million).

4. REVENUES

The significant categories of revenues recognized during the year are as follows:

	2021	2020
Distribution revenue [1]	**408,004**	394,353
Transmission revenue	**683,023**	695,305
Customer contributions *(Note 13)*	**30,530**	32,336
Franchise fees & property tax revenues	**32,128**	29,909
Other	**77,295**	66,016
	1,230,980	1,217,919

(1) For the year ended December 31, 2021, revenues from distribution services include $58.1 million of unbilled revenues (2020 - $62.0 million). At December 31, 2021, $58.1 million of the unbilled trade accounts receivables are included in accounts receivable and contract assets (2020 - $62.0 million).

5. OTHER COSTS AND EXPENSES

Other costs and expenses comprise the following:

	2021	2020
Professional fees, services and contractors	**5,919**	6,882
Technology expenses	**27,724**	26,155
Insurance	**7,256**	6,538
Travel and meals	**1,273**	1,594
Office services and other costs	**737**	810
Head office fees	**43,858**	44,445
Licenses	**7,396**	7,202
Corporate license fees	**6,428**	5,155
Loss on disposal	**(158)**	–
Telecommunications	**1,612**	1,534
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**17,631**	28,002
Provision on AUC enforcement proceeding (*Note 3, 21*)	**43,037**	–
Other	**25,897**	19,292
	188,610	147,609

6. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2021	2020
Long-term debt	**228,060**	230,595
Amortization of deferred financing charges	**1,307**	1,159
Other	**4,039**	3,042
	233,406	234,796
Less: interest capitalized *(Notes 8, 9)*	**(317)**	(5,131)
	233,089	229,665

Borrowing costs capitalized to property, plant and equipment and intangibles during 2021 were calculated by applying a weighted average interest rate of 4.58 per cent (2020 - 4.52 per cent) to expenditures on qualifying assets.

7. INCOME TAXES

INCOME TAX EXPENSE

The income tax rate for 2021 is 23.0 per cent (2020 - 24.0 per cent).

The components of income tax expense for the year ended December 31 are summarized below.

	2021	2020
Current income tax expense		
Expenses for the year	**1,994**	1,575
Adjustment in respect of prior years	**1,006**	–
	3,000	1,575
Deferred income tax expense		
Reversal of temporary differences	**62,389**	65,683
Change in income taxes resulting from decrease in provincial corporate tax rate	–	4,960
Adjustment in respect of prior years	**(341)**	875
	62,048	71,518
	65,048	73,093

The reconciliation of statutory and effective income tax expense for the year ended December 31 is as follows:

	2021		2020	
Earnings before income taxes	**255,762**	**%**	302,055	%
Income taxes, at statutory rates	**58,825**	**23.0**	72,493	24.0
Dividend income	**(1,950)**	**(0.8)**	(2,124)	(0.7)
Non-deductible differences	**7,116**	**2.8**	–	–
Part VI.I tax net of transfer benefit	**389**	**0.1**	364	0.1
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	4,960	1.6
Statutory and deferred tax variance	–	–	(2,922)	(1.0)
Other	**668**	**0.3**	322	0.1
	65,048	**25.4**	73,093	24.1

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations and Other	Total
December 31, 2019	830,912	45,305	(53,849)	(7,159)	815,209
Charge (credit) to earnings	80,991	(187)	(3,907)	(10,339)	66,558
Credit to other comprehensive income	–	–	–	(1,250)	(1,250)
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	4,960	–	4,960
December 31, 2020	911,903	45,118	(52,796)	(18,748)	885,477
Charge (credit) to earnings	**66,262**	**(8,023)**	**3,015**	**794**	**62,048**
Credit to other comprehensive income	–	–	–	**1,940**	**1,940**
December 31, 2021	**978,165**	**37,095**	**(49,781)**	**(16,014)**	**949,465**

The Company does not expect its deferred income tax liabilities to reverse within the next twelve months (2020 - nil).

At December 31, 2021, the Company had $217 million of non-capital tax losses and credits which expire between 2035 and 2041. The Company recognized deferred income tax assets of $50 million for these losses and credits.

8. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2019	11,020,655	409,260	185,048	542,218	12,157,181
Additions	1,003	–	321,832	–	322,835
Transfers	265,750	2,662	(295,752)	27,340	–
Retirements and disposals	(25,856)	(5,413)	–	(17,793)	(49,062)
December 31, 2020	11,261,552	406,509	211,128	551,765	12,430,954
Additions	**100**	–	**288,922**	–	**289,022**
Transfers	**264,351**	**5,110**	**(287,494)**	**18,033**	–
Retirements and disposals	**(57,667)**	**2,006**	–	**(15,170)**	**(70,831)**
Related party transfers	–	–	–	**(63)**	**(63)**
December 31, 2021	**11,468,336**	**413,625**	**212,556**	**554,565**	**12,649,082**
Accumulated depreciation					
December 31, 2019	2,395,765	76,860	–	245,505	2,718,130
Depreciation	228,754	10,223	–	33,641	272,618
Retirements and disposals	(25,856)	(5,413)	–	(17,793)	(49,062)
December 31, 2020	2,598,663	81,670	–	261,353	2,941,686
Depreciation	**235,741**	**12,529**	–	**33,271**	**281,541**
Retirements and disposals	**(59,400)**	**2,102**	–	**(15,170)**	**(72,468)**
Related party transfers	–	–	–	**(63)**	**(63)**
December 31, 2021	**2,775,004**	**96,301**	–	**279,391**	**3,150,696**
Net book value					
December 31, 2020	8,662,889	324,839	211,128	290,412	9,489,268
December 31, 2021	**8,693,332**	**317,324**	**212,556**	**275,174**	**9,498,386**

In 2021, the additions to property, plant and equipment included a write-down of interest capitalized during construction of $1.8 million mainly due to canceled projects. In 2020, interest capitalized during construction included in the additions to property, plant and equipment was $3.9 million.

9. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Work-in-Progress	Total
Cost				
December 31, 2019	195,180	229,416	34,565	459,161
Additions	–	–	36,725	36,725
Transfers	22,950	11,819	(34,769)	–
Retirements	(22,451)	–	–	(22,451)
December 31, 2020	195,679	241,235	36,521	473,435
Additions	**–**	**–**	**48,943**	**48,943**
Transfers	**15,931**	**5,550**	**(21,481)**	**–**
Retirements	**(14,200)**	**(58)**	**–**	**(14,258)**
December 31, 2021	**197,410**	**246,727**	**63,983**	**508,120**
Accumulated amortization				
December 31, 2019	102,610	32,154	–	134,764
Amortization	26,064	4,523	–	30,587
Retirements	(22,451)	–	–	(22,451)
December 31, 2020	106,223	36,677	–	142,900
Amortization	**21,262**	**2,903**	**–**	**24,165**
Retirements	**(14,200)**	**(58)**	**–**	**(14,258)**
December 31, 2021	**113,285**	**39,522**	**–**	**152,807**
Net book value				
December 31, 2020	89,456	204,558	36,521	330,535
December 31, 2021	**84,125**	**207,205**	**63,983**	**355,313**

In 2021, the additions to intangibles included $2.1 million of interest capitalized during construction (2020 - $1.2 million).

In 2021, the Company recorded a decrease to intangibles of $1.8 million with a corresponding increase to other expenses in the statement of non-consolidated statement of earnings as a result of the review of the impacts of IFRIC on recognition of certain configuration and customization expenditures related to cloud computing costs (Note 2).

10. INVESTMENTS

The investment in subsidiary companies at December 31 is as follows:

Investee	Principal place of business	Percentage ownership	2021	2020
ATCO Electric Yukon	Whitehorse, Yukon	100%	**12,171**	12,171
Norven Holdings Inc.	Edmonton, Alberta	100%	**4,164**	4,164
			16,335	16,335

In 2021, the Company received $8.5 million in cash dividends from its subsidiaries (2020 - $8.9 million).

The Company has an 80 per cent interest in ATCO-Valard Design Build Joint Venture. ATCO-Valard Design Build Joint Venture is an unincorporated joint arrangement between the Company and Valard Construction LP, a subsidiary of Quanta Services, Inc., for the purpose of developing, designing and building the Fort McMurray West 500-kilovolt (kV) Transmission Project.

11. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2021	2020
Debentures - unsecured [1]	4.505% (2020 - 4.553%)	**5,076,644**	5,017,643
Other long-term obligation, due June 2023 - unsecured [2]	2.450% (2020- 2.450%)	**6,870**	6,270
Less: deferred financing charges		**(27,241)**	(26,991)
		5,056,273	4,996,922
Less: amounts due within one year		**(50,010)**	(101,000)
		5,006,263	4,895,922

(1) Interest rate is the average effective interest rate weighted by principal amounts outstanding.

(2) During 2021, the expiry date of the CU Inc. other long-term obligation was extended from June 2022 to June 2023.

Debenture Issuances

During 2021, the Company issued $160 million of 3.174 per cent debentures maturing on September 5, 2051 (2020 - $25.0 million of 2.609 per cent debentures maturing on September 28, 2050).

During 2021, the Company repaid $101 million of 4.801 per cent debentures on November 22, 2021 (2020 - $38.2 million of 11.770 per cent debentures on November 30, 2020).

12. RETIREMENT BENEFITS

The Company, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-registered non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2021.

Information about the Company's participation in the group benefit plans is as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**5,629**	**1,912**	9,030	1,919
Defined contribution plans cost	**8,620**	**–**	8,626	–
Total cost	**14,249**	**1,912**	17,656	1,919
Less: capitalized	**9,405**	**1,259**	11,578	1,259
Net cost recognized	**4,844**	**653**	6,078	660
Accrued benefit obligations				
Beginning of year	25,167	42,100	21,836	37,533
Defined benefit plan cost	**5,629**	**1,912**	9,030	1,919
Benefit payments	**(3,004)**	**(1,190)**	(3,354)	(1,118)
Contributions to defined benefit plans	**(3,052)**	**–**	(4,088)	–
Actuarial (gains) losses	**(3,670)**	**(4,765)**	1,743	3,766
End of year	**21,070**	**38,057**	25,167	42,100

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Average compensation increase for the year	**2.25 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.16 %**	**3.16 %**	2.58 %	2.58 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.05 %**	n/a	5.11 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) The Company uses a graded drug cost trend rate which assumes a 5.05 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2020 was completed in 2021 for the registered defined benefit pension plans. The estimated contribution for 2022 is $3.0 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2023.

13. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2021	2020
Trade accounts receivable and contract assets	**129,632**	133,802
Other accounts receivable	**14,642**	1,736
	144,274	135,538

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2021	2020
Trade accounts receivable from parent and affiliate companies	**2,276**	3,751
Other accounts receivable from parent and affiliate companies	**1,030**	1,340
	3,306	5,091

The significant changes in trade accounts receivable and contract assets are as follows:

December 31, 2019	137,599
Revenue from satisfied performance obligations	1,160,576
Credit loss allowance	(945)
Payments received	(1,163,428)
December 31, 2020	133,802
Revenue from satisfied performance obligations	**1,179,638**
Payments received	**(1,183,808)**
December 31, 2021	**129,632**

CUSTOMER CONTRIBUTIONS AND OTHER DEFERRED REVENUES

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Customer contributions and other deferred revenues at December 31 are as follows:

	2021	**2020**
Customer contributions	**1,040,262**	975,195
Other deferred revenues	**6,347**	5,679
	1,046,609	980,874

Changes in customer contributions balance are summarized below.

December 31, 2019	978,467
Receipt of customer contributions	29,064
Amortization	(32,336)
December 31, 2020	975,195
Receipt of customer contributions	**95,597**
Amortization	**(30,530)**
December 31, 2021	**1,040,262**

14. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2021		**2020**
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**2,440,000**	**61,000**	2,440,000	61,000
2.292% Series 4	**1,560,000**	**39,000**	1,560,000	39,000
Issuance costs		**(1,720)**		(1,720)
		98,280		98,280

Rights and privileges

Preferred shares	Redemption Amount [1]	Quarterly Dividend [2]	Reset Premium [3]	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.14325	1.36 %	June 1, 2026 [4]	Series 5 [5]

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

	2021		2020	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	–	–	1,748,578	43,714
Issuance costs		–		(44)
		–		43,670

In 2021, the Company redeemed all of the issued 4.60 per cent Series V Preferred Shares for $44 million plus accrued dividends.

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of the Company at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2021	2020
Cumulative Redeemable Preferred Shares		
4.60% Series 1	**1.1500**	1.1500
2.292% Series 4 [1]	**0.5669**	0.5608
Perpetual Cumulative Second Preferred Shares		
4.60% Series V [2]	**0.7456**	1.1500

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.243 per cent.

(2) The 4.60% Series V Preferred Shares were redeemed on August 27, 2021.

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 20, 2022, the Company declared first quarter eligible dividends of $0.28750 per Series 1 Preferred Share and $0.14325 per Series 4 Preferred Share.

15. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2021 and 2020	**23,598,608**	**743,698**	**14,463,663**	**468,730**	**38,062,271**	**1,212,428**

Class A and B shares have no par value.

The Company declared and paid cash dividends of $7.94 per Class A non-voting share and Class B common share during 2021 (2020 - $8.25). The payment and amount of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On February 18, 2022, ATCO Electric declared a first quarter dividend of $1.87 per Class A and Class B share.

16. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities for the year ended December 31 are summarized below.

	2021	2020
Depreciation and amortization	**311,608**	298,731
Income tax expense	**65,048**	73,093
Contributions by customers for extensions to plant	**95,597**	29,064
Amortization of customer contributions	**(30,530)**	(32,336)
Net finance costs	**227,274**	224,223
Income taxes paid	**(2,221)**	(1,483)
Provision on early termination of the master service agreement for managed IT services *(Note 3)*	**–**	28,002
Other	**(16,530)**	(12,556)
	650,246	606,738

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital for the year ended December 31 are summarized below.

	2021	2020
Operating activities		
Accounts receivable and contract assets	**4,479**	7,692
Accounts receivable from parent and affiliate companies	**1,475**	1,575
Inventories	**366**	(276)
Prepaid expenses and other current assets	**57**	105
Accounts payable and accrued liabilities	**7,651**	(8,275)
Accounts payable to parent and affiliate companies	**14,212**	(9,604)
Provisions and other current liabilities	**31,139**	614
	59,379	(8,169)
Investing activities		
Accounts receivable and contract assets	**(13,215)**	(4,057)
Accounts receivable from parent and affiliate companies	**345**	(478)
Accounts payable and accrued liabilities	**(6,660)**	(10,297)
	(19,530)	(14,832)

CASH POSITION

Cash position at December 31 is comprised of:

	2021	2020
Cash	**15,467**	4,854
Short-term advances to parent and affiliate companies *(Note 23)*	**2,999**	29,000
Cash and cash equivalents	**18,466**	33,854
Bank indebtedness	**(3,021)**	–
Short-term advances from parent and affiliate companies *(Note 23)*	**(54,700)**	(109,000)
	(39,255)	(75,146)

17. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash, short-term advances to parent company, accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent and affiliated companies, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company's financial instruments measured at amortized cost are as follows:

			2021		2020
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Liabilities					
Long-term debt	11	**5,056,273**	**6,100,162**	4,996,922	6,490,818

OFFSETTING FINANCIAL ASSETS

At December 31, the following financial assets are subject to offsetting, enforceable master netting arrangements and similar agreements:

			2021			2020
Financial Assets	Gross Amount	Gross Amount Offset	Net Amount Recognized	Gross Amount	Gross Amount Offset	Net Amount Recognized
Accounts receivable and contract assets	**64,733**	**(38,734)**	**25,999**	60,541	(38,674)	21,867

18. RISK MANAGEMENT

The Company is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to the share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparties inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents and accounts receivable and contract assets and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the non-consolidated balance sheet.

The company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

The majority of the Company's accounts receivable and contract assets credit risk is reduced by financial security provided by Direct Energy and by retailers in accordance with provisions contained within the Electric Utilities Act Distribution Tariff Regulation A.R. 162/2003, and the Company's ability under the Regulation to recover through its distribution tariff any costs not recovered by a claim against such retailer security. At December 31, 2021, the Company held $105 million in letters of credit for certain counterparty receivables (2020 - $92 million).

Accounts receivable and contract assets are non-interest bearing and are generally due in 30 to 90 days. The credit loss allowance recorded in 2021 was nil and the reversal of prior year's credit write-off was $1.5 million (2020 - $1.3 million and nil). The credit loss allowance balance at December 31, 2021, was $0.4 million (2020 - $0.9 million). At December 31, 2021, the Company had $2.7 million of trade receivables past due greater than 30 days (2020 - $3.9 million). No other impairments have been identified within accounts receivable or contract assets.

The Company has also entered into guarantee arrangements with Direct Energy's parent company (NRG Energy) relating to the retail energy supply functions performed by Direct Energy (see Note 21).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Lines of credit

At December 31, 2021, the Company has a line of credit of $10.0 million (2020 - $10.0 million). The credit line enables the Company to obtain financing for general business purposes. At December 31, 2021, $10.0 million of the credit line was available (2020 - $10.0 million).

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities, of the Company's financial liabilities at December 31, 2021 based on the contractual undiscounted cash flows.

	2022	2023	2024	2025	2026	2027 and thereafter
Bank indebtedness	3,021	_	_	_	_	_
Short-term advances from parent and affiliated companies	54,700	_	_	_	_	_
Accounts payable and accrued liabilities	101,003	_	_	_	_	_
Accounts payable to parent and affiliate companies	72,670	_	_	_	_	_
Long-term debt:						
Principal	50,010	30,404	116,000	_	_	4,887,100
Interest expense	225,487	222,270	212,640	211,323	211,323	4,104,002
	506,891	252,674	328,640	211,323	211,323	8,991,102

The table below analyzes the remaining contractual maturities, of the Company's financial liabilities at December 31, 2020 based on the contractual undiscounted cash flows.

	2021	2022	2023	2024	2025	2026 and thereafter
Short-term advances from parent and affiliated companies	109,000	_	_	_	_	_
Accounts payable and accrued liabilities	100,020	_	_	_	_	_
Accounts payable to parent and affiliate companies	57,340	_	_	_	_	_
Long-term debt:						
Principal	101,000	56,280	23,534	116,000	_	4,727,099
Interest expense	218,388	215,105	212,312	205,673	204,370	3,088,023
	585,748	271,385	235,846	321,673	204,370	7,815,122

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact the Company. This includes causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company’s operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company’s business.

While the Company’s investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on the Company remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across the Company. As a result of these efforts and the Company’s experience in crisis response, the Company’s operations, financial position and performance have not been significantly impacted for the year ended December 31, 2021.

CLIMATE CHANGE RISK

The Company manages climate risks related to assets, including preparing for, and responding to, extreme weather events through activities such as proactive route and site selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital expenditures or acquiring assets, The Company considers site specific climate and weather factors, such as flood plain mapping and extreme weather history.

The Company also continues to explore and implement opportunities in energy efficiency. This process is associated with risks and uncertainties, and is highly dependent on changes in legislation, market price volatility, local and global demand on energy, as well as the timing of when the local and global markets transition to a more energy efficient and cleaner fuels-based economy. The extent and significance of the future impact of such risks and uncertainties remain unknown.

19. CAPITAL DISCLOSURES

The Company's objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for the Company. In October 2020, the Company received the 2021 generic cost of capital decision. The decision established the equity ratio for 2021 at 37.0 per cent for transmission and distribution operations. The capitalization involves the use of long term debt and preferred share financings.

The Company includes share owner's equity, preferred shares, and-long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 3 and 24), in its determination of capitalization. In maintaining or adjusting its capital structure, the Company may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, and long-term debt.

20. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by the AUC. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Leases

The Company evaluates contract terms and conditions to determine whether they contain or are leases. Where a lease exists, the Company determines whether substantially all of the significant risks and rewards of ownership are transferred to the customer, in which case it is accounted for as a finance lease, or remain with the Company, in which case it is accounted for as an operating lease.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management’s best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of electricity. The estimate is derived from unbilled electricity distribution services supplied to customers and is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 18.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, ATCO Electric identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 12.

Asset retirement obligations

ATCO Electric estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

Use of judgments and estimates around the COVID-19 pandemic

For the year ended December 31, 2021, the Company performed an assessment of the impacts of uncertainties around the COVID-19 pandemic on its non-consolidated financial position, financial performance and cash flows. The assessment required use of judgments and estimates and resulted in no material impacts to the non-consolidated financial statements.

21. CONTINGENCIES

AUC enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether the Company failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and the Company are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $43 million ($41.1 million after-tax) related to the proceeding.

Measurement inaccuracies

Measurement inaccuracies occur from time to time on electricity and gas metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

Direct Energy Partnership retail obligation

In 2004, ATCO Gas and ATCO Electric Distribution transferred their retail energy supply businesses to Direct Energy Partnership (Direct Energy). The legal obligations of ATCO Gas and ATCO Electric Distribution for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric Distribution, with no refund of the transfer proceeds to Direct Energy.

NRG Energy Inc. (NRG), Direct Energy's parent company, provided a $300 million guarantee, supported by a $300 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric Distribution under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

Other

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the non-consolidated financial statements.

22. COMMITMENTS

In addition to commitments disclosed elsewhere in the non-consolidated financial statements, the Company has entered into a number of operating leases for office premises and equipment and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter
Purchase obligations:						
Operating and maintenance agreements	28,015	12,125	11,529	3,839	–	–
Capital expenditures	181,061	–	–	–	–	–
	209,076	12,125	11,529	3,839	–	–

23. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Electric entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2021	2020
CU Inc. / Canadian Utilities Limited / ATCO Ltd.	Parent	Contract Services	Revenue	**82**	–
		Administration, financial management, aircraft and rent	Other expenses	**49,604**	47,303
		Aircraft, rent and leasehold improvements	Property, plant and equipment	**13,517**	15,930
		Licensing fees	Other expenses	**6,428**	5,155
		Interest income	Interest income	**148**	428
		Long-term and short-term interest expense and guarantee fees	Interest expense	**229,845**	232,179
Northland Utilities Enterprises Ltd.	Subsidiary	Administration, financial management, engineering services, materials management and metering services	Revenues	**1,811**	1,342
		Long-term and short-term interest income	Interest income	**1,511**	1,520
ATCO Electric Yukon	Subsidiary	Administration, financial management, materials management and metering services	Revenues	**892**	769
		Long-term and short-term interest income	Interest income	**3,241**	3,264
		Short-term interest expense	Interest expense	**14**	21
ATCO Structures & Logistics	Affiliate	Administration and camp services	Other expenses	**13**	39
		Trailer supply and noise management services and purchase of	Property, plant and equipment	**40**	–
		Project Services	Revenues	**–**	63
ATCO Gas	Affiliate	Administration and rent	Revenues	**329**	348
		Contract services	Revenues	**1,501**	1,092
		Administration, rent, joint trenching, electronics and instrumentation testing and purchase of	Other expenses	**–**	341
		Contract services	Other expenses	**134**	–
		Contract services	Property, plant and equipment	**1,206**	979

Entity	Relationship	Transaction	Recorded As	2021	2020
ATCO Power	Affiliate	Transfer of assets	Property, plant and equipment	**–**	–
ASHCOR	Affiliate	Contract services	Revenues	**–**	84
ATCO Power (2010) Ltd.	Affiliate	Contract services	Revenues	**7,871**	13,759
ATCO Energy Solutions Ltd.	Affiliate	Operate and maintain facilities, project services, communication services and administration	Revenues	**327**	192
ATCO Investments Ltd.	Affiliate	Contract services	Revenues	**124**	108
		Rent	Rent, parking and utilities	**780**	824
ATCO Land Holdings	Affiliate	Contract services	Revenues	**2**	–
ATCO Frontec	Affiliate	Contract services	Property, plant and equipment	**49**	–
ATCO Pipelines	Affiliate	Contract services	Revenues	**317**	87
ATCO Energy Ltd.	Affiliate	Billing and call centre services	Revenues	**45**	53
		Retail service revenue	Revenues	**66,310**	56,341
		Distribution service costs	Other expenses	**1,008**	843
		Contract services	Other expenses	**–**	2
		Contract services	Property, plant and equipment	**5**	–
ATCO Infrastructure Solutions Ltd.	Affiliate	Contract services	Revenues	**6,253**	3,729
2200427 Alberta Ltd.	Affiliate	Financial & Administrative services	Revenues	**–**	3

Affiliate companies are subsidiaries of ATCO Electric’s parent or ultimate parent.

ATCO Electric incurred $0.5 million (2020 - $0.3 million) in advertising and promotion expenses from an entity related through common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2021	2020
Receivables from related parties [1]	Accounts receivable from parent and affiliate companies	**3,306**	5,091
Payables to related parties [1]	Accounts payable to parent company and affiliate companies	**72,670**	57,340
Short-term advances [2]	Short-term advances to parent company	**2,999**	29,000
	Short-term advances from parent and affiliate companies	**54,700**	109,000
Long-term advances *(Note 11)*	Long-term debt to parent company	**5,056,273**	4,996,922
Equity preferred shares *(Note 14)*	Equity preferred shares to parent company	**98,280**	141,968

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

Long-term advances to subsidiary companies

Long-term advances to subsidiary companies are shown in the table below.

	Effective Interest Rate	2021	2020
Yukon Electric			
Debentures - unsecured [1]	4.535% (2020 - 4.535%)	**70,800**	70,800
Northland Utilities Yellowknife			
Debentures - unsecured [1]	4.789% (2020 - 4.815%)	**24,063**	24,063
Northland Utilities NWT			
Debentures - unsecured [1]	3.850% (2020 - 3.850%)	**9,160**	9,160
		104,023	104,023

(1) Interest is the average effective interest rate weighted by principal amounts outstanding. The debentures mature between May 2023 and November 2052. Long-term advances are unsecured and will be settled in cash. No provisions are held against the advances.

24. ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

The Company is regulated by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, and service area.

Distribution Operations

The distribution operations of the Company are under a form of rate regulation called Performance Based Regulation (PBR). The current PBR period applies for a period of five years from 2018 to 2023. PBR allows distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five year period.

Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow the Company to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control, that are material, should not have significantly influenced the I Factor, are prudently incurred, are recurring and could vary greatly from year to year (Y Factor) or are unforeseen and unlikely to recur (Z Factor).

Transmission Operations

The transmission operations of the Company are subject to a cost of service regulation under which the AUC establishes the revenues required to: (1) recover forecast operating costs of providing the regulated service, including depreciation and amortization and income taxes, and (2) provide a fair and reasonable return on utility investment, or rate base. Since actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the investment in property, plant and equipment and intangible assets approved by the AUC. The investment includes an allowance for working capital and is reduced by accumulated depreciation and amortization, reserves for future removal and site restoration costs, and unamortized contributions by utility customers for plant extensions. These operations earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base which is based on the historical and forecast weighted average cost of debt and preferred shares. The AUC also establishes the capital structure.

The transmission operations of the Company seek approval for their revenue requirement either by submitting a general tariff application to the AUC or negotiating settlement with interested parties. In the latter case, the AUC monitors the negotiated settlement process and approves any agreement. The AUC may approve interim rates or the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the company does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Company records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Electricity transmission

Revenue from electricity transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity distribution

Revenue from distribution of electricity is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity is based on tariff-approved rates established by the Alberta Electric Systems Operator and rates stipulated in contracts respectively. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission and distribution prices. The recovery is part of the provision of continuous electricity transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. The tax effect of temporary differences from investments in subsidiaries are not accounted for where the Company is able to control the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

Current income tax assets and liabilities are offset where the Company has the legally enforceable right to offset and the Company intends to either settle on a net basis or realize the asset and settle the liability simultaneously.

Deferred income tax assets and liabilities are offset where the Company has a legally enforceable right to set off tax assets and liabilities, and when the deferred income tax assets and liabilities relate to income taxes levied by the same tax authority.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

INVESTMENTS

The Company's investment in subsidiary companies is initially recognized at cost and only dividends received are taken into earnings. The exemption from applying the consolidation method has been used.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	25 to 67 years	51 years	1.9 %
Electricity distribution equipment	15 to 55 years	44 years	2.3 %
Buildings	45 to 50 years	40 years	2.5 %
Other plant, equipment and machinery	5 to 25 years	19 years	5.3 %

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and 75 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU’s carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU’s fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

PROVISIONS

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event;

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the non-consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, included in other liabilities, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the non-consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

The Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Company is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2019.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. The Company does not have any liability to the Group Plan other than the minimum funding requirements of its subsidiaries. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

The Company participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Company accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, the Company is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the non-consolidated statements of earnings.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2021, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

25. SUBSEQUENT EVENTS

The AUC enforcement branch and ATCO Electric Transmission commenced settlement discussions in January 2022. On March 18, 2022, the AUC enforcement branch and ATCO Electric Transmission concluded discussions and notified the AUC that the parties had reached a settlement on all matters. On April 14, 2022, the settlement was filed with the AUC, reflecting an agreed administrative penalty of $31 million, the removal of $11 million in project costs from rate base, and the implementation of revised practices and policies. The AUC is currently determining the next process steps.

May 13, 2022

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Attention: Kristjana Kellgren
Executive Director, Rates Division

Re: ATCO Gas Distribution
AUC Rule 005
Annual Reporting of Financial and Operational Results

In accordance with the Alberta Utilities Commission (AUC or the Commission) Rule 005, please find enclosed ATCO Gas Distribution's (AGD) 2021 Annual Reporting of Financial and Operational Results.

Should you have any questions regarding this submission, please do not hesitate to contact the undersigned at (587) 983-4054 or jennifer.bagnall@atco.com if you have any questions or require further information.

Yours truly,

Jennifer Bagnall, CPA, CMA
Director, Regulatory

SCHEDULE 1

ATCO Gas

SUMMARY OF REVENUE REQUIREMENT

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 (Normalized where applicable) #	%
1	Return on Rate Base	Sch. 2 / 10	192,056	204,785	12,729	6.63%
2	Operating and Maintenance Expense	Sch. 3	464,923	513,826	48,903	10.52%
3	Depreciation & Amortization Expense	Sch. 4 / 10	199,937	206,899	6,962	3.48%
4	Income Taxes	Sch. 5 / 10	24,838	19,911	(4,927)	(19.84%)
5	Property and Other Tax Expense		593	626	33	5.56%
6	Sub Total Utility Revenue Requirement		882,347	946,047	63,700	7.22%
7	Flow Through Expenses	Sch. 6 / 10	207,262	225,390	18,128	8.75%
8	**Total Utility Revenue Requirement**	Sch. 6 / 10	**1,089,609**	**1,171,437**	**81,828**	**7.51%**
	Detailed Revenue					
9	Rate Revenue	Sch. 6	824,763	893,166	68,403	8.29%
10	Franchise Fee Revenue	Sch. 6 / 10	207,262	225,390	18,128	8.75%
11	Interim Rates and AUC Decisions	Sch. 6	34,354	30,390	(3,964)	(11.54%)
12	Other Revenue	Sch. 6	23,230	22,491	(739)	(3.18%)
13	**Utility Revenue**	Sch. 6 / 10	**1,089,609**	**1,171,437**	**81,828**	**7.51%**

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.
(2) Total Revenue Requirement must be reconciled on Schedule 10 to the Audited Financial Statements.
(3) Provide a detailed breakdown of items included in Revenue Offsets and Other Revenue in a supporting sub-schedule.
(4) Please provide a footnote stating the source of the approved forecast or approval of the negotiated settlement.
(5) The original applied for forecast is for information purposes only and a variance explanation is not required.
(6) Provide the application number where the applied for forecast information was obtained.
(7) Please identify flow through items and any reporting anomalies.
(8) If figures are unavailable for a given category please leave bank and make a notation at the bottom of the schedule or in the variance explanation as to the reason they are unavailable.
(9) List the flow through items included in line 8. Flow through items may or may not include franchise fees and natural gas supply.

Variance Explanations

Cross-Ref	
2	**Operating and Maintenance Expense** - See Schedule 3.
3	**Depreciation & Amortization Expense** - See Schedule 4.
4	**Income Taxes** - See Schedule 5.
7	**Flow Through Expenses** - See Schedule 6.
9	**Rate Revenue** - See Schedule 6.
10	**Franchise Fee Revenue** - See Schedule 6.
11	**Interim Rates and AUC Decisions** - See Schedule 6.

ATCO Gas

SUMMARY OF RETURN ON RATE BASE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross Ref.	Actual Current Year End	Actual Previous Year End	Actual Mid-Year Capital	Deemed Ratio	Prorated Rate Base	Cost Rate %	Return $
1	Debt	Sch. 2.3	1,771,589	1,711,777	1,741,683	60.29%	1,721,704	4.48%	77,209
2	Preferred Shares	Sch. 2.4	65,500	89,561	77,531	2.71%	77,531	3.65%	2,832
3	Common Equity		1,065,950	1,035,203	1,050,576	37.00%	1,056,697	11.81%	124,744
4	Mid-Year Invested Capital		2,903,039	2,836,541	2,869,790	100.00%	2,855,931	7.17%	
5	Return on Rate Base	Sch. 1 / 10							204,785
6	No Cost Capital						701		
7	Total Mid-year Rate Base	Sch. 2.1					2,856,632		

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.
(2) Provide the breakdown of the items making up the difference (including disallowed items etc.).
(3) Common equity is based on the approved equity ratio.
(4) Please complete these schedules using the approved deemed capital structure.
(5) The cost rate for the common equity should be inferred from the return and prorated rate base of common equity.

ATCO Gas

SUMMARY OF MID-YEAR RATE BASE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Property, Plant and Equipment - Utility					
1	Opening Balance		5,431,086	5,470,814	39,728	0.73%
2	Expenditures	Sch. 4.1 / 4.2	240,751	305,382	64,631	26.85%
3	Retirements	Sch. 4.1	(197,938)	(48,358)	149,580	(75.57%)
4	Transfers and Adjustments	Sch. 4.1	(3,085)	3,078	6,163	(199.75%)
5	Closing Balance	Sch. 4.1	5,470,814	5,730,916	260,101	4.75%
6	**Mid-Year Property, Plant and Equipment**		5,450,950	5,600,865	149,915	2.75%
	Accumulated Depreciation - Utility					
7	Opening Balance		2,041,785	2,088,017	46,232	2.26%
8	Depreciation Expense	Sch. 4	253,399	222,291	(31,108)	(12.28%)
9	Retirements	Sch. 4.1	(197,938)	(48,358)	149,580	(75.57%)
10	Proceeds from Disposals of Capitalized Assets	Sch. 4.1	2,984	3,882	898	30.10%
11	Removal, Depreciation Capitalized and Other Transfers		(12,213)	(11,711)	502	(4.11%)
12	Closing Balance	Sch. 4.1	2,088,017	2,254,122	166,104	7.96%
13	**Mid-Year Accumulated Depreciation**		2,064,901	2,171,069	106,168	5.14%
	Contributions in Aid of Construction					
14	Opening Balance	Sch. 4.1	(767,145)	(791,609)	(24,464)	3.19%
15	Closing Balance	Sch. 4.1	(791,609)	(827,596)	(35,986)	4.55%
16	**Mid-Year Contributions in Aid of Construction**		(779,377)	(809,602)	(30,225)	3.88%
	Amortization of Contributions					
17	Opening Balance	Sch. 4.1	233,955	243,376	9,420	4.03%
18	Closing Balance	Sch. 4.1	243,376	258,398	15,022	6.17%
19	**Mid-Year Amortization of Contributions**		238,666	250,887	12,221	5.12%
20	Less: Construction Work in Progress (CWIP) - Mid-Year		(84,578)	(95,245)	(10,667)	12.61%
21	Less: Contributions Work in Progress (KWIP) - Mid-Year		3,052	3,336	284	9.31%
22	**Construction Work in Progress (CWIP) - Mid-Year**		(81,526)	(91,909)	(10,383)	12.74%
23	**Mid-Year Utility Plant in Service**		2,763,812	2,779,171	15,359	0.56%
	Necessary Working Capital					
24	Cash Expenses		1,649	4,885	3,236	196.24%
25	Materials and Supplies		3,552	3,540	(12)	(0.34%)
26	Prepayments and Deferrals		31,823	59,439	27,616	86.78%
27	Financial Items		4,641	9,129	4,488	96.70%
28	Goods and Services Tax (GST)		(86)	468	554	(644.19%)
			41,579	77,461	35,882	86.30%
29	**Mid Year Rate Base**	Sch. 2	**2,805,391**	**2,856,632**	**51,241**	**1.83%**

ATCO Gas
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Guidelines:
(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.
(2) If there was a negotiated settlement in place for the reporting year please state the approved negotiated settlement numbers in the decision c
(3) Please note the source of the numbers in the decision or negotiated settlement as applicable.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2018, 2019 and 2020

Variance Explanations

Cross-Ref	
2	**Expenditures** see Schedule 4.2.
3/9	**Retirements** are lower than prior year mainly due to Decision 24188-D02-2020 which approved the use of amortization accounting for a number of accounts including Software and Leasehold Improvements resulting in retirements for balances older than the approved amortization period in 2020.
4	**Adjustments and Transfers** are higher than prior year mainly due to asset transfers between ATCO Pipelines and ATCO Gas associated with the Urban Pipelines Replacement (UPR) Program.
8	**Depreciation Expense** refer to Schedule 4.0.
20	**Construction Work in Progress (CWIP)** is higher than prior year primarily due to IT projects as a result of the continued work on the ATCO Gas CIS Replacement Program.
24	**Cash Expenses** are higher mainly due to income taxes and higher operation and maintenance.
26	**Prepayments and deferrals** are higher than the prior year mainly due to the outstanding collection resulting from the implementation of approved depreciation parameters as per Decision 24188-D02-2020.
27	**Financial Items** are higher than the prior year mainly due to lower dividends.

SCHEDULE 2.2

ATCO Gas

SUMMARY OF MID YEAR CAPITAL STRUCTURE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross Ref.	Actual Current Year End	Actual Previous Year End	Actual Mid-Year Capital
1	Debt	Sch. 2.3	1,771,589	1,711,777	1,741,683
2	Preferred Shares	Sch. 2.4	65,500	89,561	77,531
3	Common Equity	Sch. 11	1,065,950	1,035,203	1,050,576
4	Total Mid-Year Invested Capital		2,903,039	2,836,541	2,869,790

ATCO Gas
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

2021 Actual

Line No.	Cross-Reference	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Underwriting Discount & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Carrying Cost	Average Embedded Cost Rate
1		B	9.920%	91/12/18	2022	9.920%	26,803	(13)	26,790	10.070%	26,790	2,698	
2		C	9.400%	92/12/08	2023	9.400%	43,629	(59)	43,570	9.512%	43,570	4,144	
3		H	5.896%	04/11/18	2034	5.896%	57,000	(218)	56,782	5.940%	56,782	3,373	
4		I	5.183%	05/11/21	2035	5.183%	20,000	(85)	19,915	5.227%	19,915	1,041	
5		K	5.032%	06/11/20	2036	5.032%	20,000	(83)	19,917	5.072%	19,917	1,010	
6		L	5.556%	07/11/30	2037	5.556%	65,000	(287)	64,713	5.597%	64,713	3,622	
7		M	5.563%	08/05/26	2028	5.563%	55,000	(454)	54,546	5.619%	54,546	3,065	
8		N	5.580%	08/05/26	2038	5.580%	95,000	(163)	94,837	5.625%	94,837	5,335	
9		O	4.543%	11/06/30	2041	4.543%	114,300	(574)	113,726	4.582%	113,726	5,211	
10		P	4.593%	11/06/30	2061	4.593%	45,700	(270)	45,430	4.626%	45,430	2,102	
11		Q	3.805%	12/09/10	2042	3.805%	97,000	(494)	96,506	3.841%	96,506	3,707	
12		R	3.825%	12/09/11	2062	3.825%	39,000	(235)	38,765	3.854%	38,765	1,494	
13		S	4.722%	13/09/09	2043	4.722%	70,000	(384)	69,616	4.763%	69,616	3,316	
14		T	4.085%	14/09/09	2044	4.085%	130,000	(691)	129,309	4.122%	129,309	5,330	
15		U	3.964%	15/07/27	2045	3.964%	90,000	(538)	89,462	4.004%	89,462	3,582	
16		V	4.211%	15/10/30	2055	4.211%	45,000	(289)	44,711	4.246%	44,711	1,898	
17		X	3.763%	16/11/16	2046	3.763%	140,000	(892)	139,108	3.803%	139,108	5,290	
18		Y	3.548%	17/11/22	2047	3.548%	145,000	(930)	144,070	3.587%	144,070	5,168	
19		Z	3.950%	18/11/21	2048	3.950%	130,000	(869)	129,131	3.988%	129,131	5,150	
20		AA	2.963%	19/09/05	2049	2.963%	233,000	(1,507)	231,493	2.996%	231,493	6,936	
21		AB	2.609%	20/09/28	2050	2.609%	40,000	(271)	39,729	2.644%	39,729	1,050	
22		AC	3.174%	21/09/03	2051	3.174%	80,000	(537)	79,463	3.209%	79,463	2,550	
23	Sch. 11	**Current Year-End Balance**					**1,781,432**	**(9,843)**	**1,771,589**		**1,771,589**	**77,072**	**4.35%**
24		Prior Year-End Balance									**1,711,777**	**75,470**	4.41%
25		**Mid-Year Balance**									**1,741,683**	**76,271**	**4.38%**
26		Mid-Year Short Term Debt									-	-	2.25%
27		Bank Charges and Financing									-	1,834	
28		**Mid-Year Balance**									**1,741,683**	**78,105**	**4.48%**
29		Adjustment for Deemed Debt									(19,979)	(896)	4.48%
30	Sch. 2	**Deemed Debt**									**1,721,704**	**77,209**	**4.48%**

Guidelines:

(1) In any year where there is a new issue, provide a supporting schedule.
(2) Any differences between Decision and Actual are to be explained in a supporting working paper.
(3) Include any short-term interest-bearing debt.
(4) Variance analysis is on Carrying Cost.
(5) Total debt should equal the financial statement debt and is not expected to equal the deemed debt indicated on Schedule 2.
(6) Please provide details affecting regulated financial results such as placeholders and R & V issues underway.

Note:
In accordance with Commission Direction 4 in Decision 22570-D01-2018, the 2021 actual debt cost rate is 4.50%

Variance Explanations

Cross-Ref	
22	Series AC- Issued debentures to finance the 2021 capital program and existing rate base.

ATCO Gas
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Cross-Reference	Series	Issue Date	Dividend Rate	Stated Value of Issue	Unamortized Underwriting Discount & Expense	Net Proceeds Outstanding	Preferred Dividend Requirement	Current Year Amortization of Issue Costs	Average Embedded Cost Rate
1		V	97/10/03				-	-	-	0.000%
2		1	07/04/18	4.60%	34,000	-	34,000	1,564	-	4.600%
3		4	10/12/02	2.29%	31,500	-	31,500	722	-	2.292%
4	Sch. 11	Current Year-End Balance			65,500	-	65,500	2,286	-	3.490%
5		Prior Year-End Balance					89,561	3,377	-	3.771%
6		**Mid-Year Balance**					77,531	2,832	-	3.652%

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.

(2) In any year where there is a new issue, provide a supporting schedule.

(3) Any differences between Forecast and Actual are to be explained in a supporting documentation.

Variance Explanations

Series V preferred shares were redeemed in 2021.
Series 4 preferred shares reset in 2021.

SCHEDULE 2.5

ATCO Gas
RECONCILIATION
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.		2021 Actual
1	Return on Mid-year rate base financed by common equity - Schedule 2.0	124,744
2	Return on book value of common equity - Schedule 10	122,211
3	**Difference**	**2,532**
	Reconciliation	
4	Common Equity Return of Mid-year rate base financed by common equity	**124,744**
5	Long-Term Debt - Schedule 2.0	77,209
6	Preferred Shares - Schedule 2.0	2,832
7	**Subtotal - Utility Income**	**204,785**
8	Interest and Other Expense	(72,880)
9	Preferred Dividend Requirement	(2,989)
10	AFUDC	5,669
11	Other Income (Expense)	(4,354)
12	Non-Utility Revenue net Expense	(10,415)
13	Other (Mainly Income Tax Differences)	2,396
14	**Return on book value of common equity as per financial statements**	**122,211**

Guidelines:

(1) Please identify key areas creating the difference between the financial return and the regulated utility return contained in these spreadsheets.

(2) As a rule of thumb, five to six main points causing the variance is recommended but the utilities explanation is not limited to that number.

ATCO Gas

SUMMARY OF DEGREE DAYS, YEAR END CUSTOMERS AND THROUGHPUT

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Actual vs. Forecast #	Variance 2021 Actual vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
1	10 Year Average Normal Degree Days	4,158	4,151	4,151	-	0.00%	(7)	(0.17%)
	Number of Year End Customers							
2	Residential	1,145,193	1,160,115	1,151,936	8,179	0.71%	14,922	1.30%
3	Commercial	101,839	102,709	102,368	341	0.33%	870	0.85%
4	Industrial	345	342	346	(4)	(1.16%)	(3)	(0.87%)
5	Irrigation	4	750	7	743	10614.29%	746	18650.00%
6	Total Customers	1,247,381	1,263,916	1,254,657	9,259	0.74%	16,535	1.33%
	Normalized Throughput - TJs							
7	Residential	129,016	127,898	128,310	(412)	(0.32%)	(1,118)	(0.87%)
8	Commercial	130,042	129,801	132,495	(2,694)	(2.03%)	(241)	(0.19%)
9	Industrial	12,721	12,971	13,467	(496)	(3.68%)	250	1.97%
10	Irrigation	182	283	268	15	5.60%	101	55.49%
11	Total Normalized Throughput	271,961	270,953	274,540	(3,587)	(1.31%)	(1,008)	(0.37%)

Note:

The 2020 throughput is normalized based on the ten year average temperatures ending 2018.

The 2021 throughput is normalized based on the ten year average temperatures ending 2019.

The 2021 customers and throughput forecasts are based on AUC Decision 25863-D01-2020.

In Decision 20820-D01-2015, the Commission directed in subsequent PBR annual rate adjustment filings to provide information on the variance from forecast to actual billing determinants in each completed prior year of the PBR term, as well as identify drivers behind a variance larger than ±5 per cent on an annual basis.

Effective April 1, 2021, the irrigation fixed charge rate is only applicable from May 1 to September 30 as per Decision 25428-D01-2020. The irrigation number of year end customers has increased to 750 customers due to seasonal irrigation customers being kept active year-round as per Decision 25428-D01-2020 which became effective in 2021. Prior to 2021, irrigation customers were physically turned off after the irrigation season ended in September. This change in methodology was made after the release of Decision 25863-D01-2020 and therefore it was not incorporated in the 2021 PBR irrigation customer forecast.

ATCO Gas

SUMMARY OF OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	%
	Operating & Maintenance Expense					
1	Gas Management		617	604	(13)	(2.04%)
2	Transmission		224,640	265,821	41,181	18.33%
3	Distribution		104,772	124,486	19,714	18.82%
4	General		9,350	10,171	821	8.78%
5	Sales and Transportation Promotion		9,978	3,670	(6,308)	(63.22%)
6	Customer Accounting		14,272	15,928	1,655	11.60%
7	Administration and General		121,146	108,867	(12,278)	(10.14%)
8	**Total Operating & Maintenance Expense**		484,774	529,547	44,773	9.24%
9	Less: Non-Utility O&M	Sch. 10	19,851	15,721	(4,130)	(20.81%)
10	**Operating & Maintenance Expense - Net**	Sch. 1	464,923	513,826	48,903	10.52%

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.
(2) Global reductions refers to the reduction of fees chargeable as deemed in the rate application decision.
(3) Please add line items as needed to more clearly identify major O&M expenses.

Variance Explanations

ross - Ref

2 **Transmission** costs are higher than prior year mainly due to an increase in rates.

3 **Distribution** costs are higher than prior year mainly due to increased volumes in operational maintenance and customer services as well as lump sum NGEA bargaining payouts.

5 **Sales and Transportation Promotion** costs are lower than prior year mainly due to a decrease in non-utility sales**.**

6 **Customer Accounting** costs are higher than prior year mainly due to higher volume in customer cutoffs for non-payment.

7 **Administration and General** costs are lower than prior year mainly due to lower IT transition costs associated with the re-alignment of IT services.

9 **Non-Utility O&M** costs are lower than prior year mainly due to a decrease in non-utility sales, partially offset by an increase in sponsorships and donations.

ATCO Gas

SUMMARY OF DEPRECIATION

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Depreciation Expense					
1	Distribution Plant		185,032	191,485	6,453	3.49%
2	General Plant		34,797	35,918	1,121	3.22%
3	Sub-total	Sch. 4.1	219,829	227,403	7,574	3.45%
4	Less: Capitalized Depreciation		(4,504)	(4,505)	(1)	0.03%
5	Sub-total		215,325	222,898	7,573	3.52%
6	Non-Utility Depreciation	Sch. 4.1	(555)	(607)	(52)	9.36%
7	**Utility Depreciation Expense**	Sch. 2.1	214,770	222,291	7,521	3.50%
8	Amortization of Contributions	Sch. 4.1	(16,265)	(16,823)	(558)	3.43%
9	Non-Utility Amortization of Contributions	Sch. 4.1	32	31	(1)	(2.89%)
10	**Amortization of Contributions - Utility**		(16,233)	(16,792)	(559)	
	Other					
11	Production Abandonments		1,400	1,400	-	-
12	**Total Utility Depreciation Expense**	Sch. 1 / 10	**199,937**	**206,899**	**6,962**	**3.48%**

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2020 only.

Variance Explanations

Cross-Ref	
1	Distribution Plant is higher than the prior year due to a higher opening depreciable base as well as an increase in depreciation resulting from 2021 capital additions.

ATCO Gas
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
	Distribution							
1	Land		7,564	891	-	-	-	8,455
2	Land Rights		36,946	5,755	5	11	(22)	42,686
3	Structures & Improvements		61,191	4,358	368	10	(48)	65,144
4	Services & Alterations		1,622,861	55,514	4,444	-	(3,096)	1,670,835
5	Regulators & Meters		502,851	14,705	1,458	-	2,025	518,124
6	Mains		2,163,957	90,196	2,671	2,968	31	2,254,481
7	Measurement & Regulating Equipment		228,245	27,535	3,328	110	(1,987)	250,575
8	Meters		261,603	25,080	8,951	-	-	277,733
9	Renewable Energy		3,870	-	-	-	-	3,870
10	**Distribution**		4,889,089	224,034	21,225	3,100	(3,096)	5,091,903
	General Plant & Equipment							
11	Franchises		1,258	23	414	-	-	867
12	Land		18,403	-	-	-	-	18,403
13	Structures		147,064	2,159	100	-	-	149,123
14	Interco Contributions		242	-	-	-	-	242
15	**General Plant & Equipment**		166,966	2,183	514	-	-	168,635
	Moveable Equipment							
16	Office Furniture & Equipment		20,573	259	324	-	(33)	20,475
17	Transportation Equipment		96,630	6,042	5,747	-	-	96,925
18	Heavy Work Equipment		26,584	1,727	1,011	-	-	27,300
19	Tools & Work Equipment		29,925	2,483	1,409	-	3,098	34,097
20	Cogeneration Equipment		4,164	8	-	-	-	4,171
21	Communication Equipment		38,963	1,253	1,317	-	(292)	38,607
22	Stores & Shop and Lab Equipment		24,730	1,314	856	-	-	25,188
23	Leasehold Improvements		5,505	186	838	-	-	4,854
24	Electronic Data Processing Equipment		7,864	5,907	397	-	323	13,696
25	Base Maps		1,671	-	130	-	-	1,542
26	Software Development		97,028	24,302	15,304	-	-	106,026
27	**Moveable Equipment**		353,636	43,480	27,333	-	3,096	372,879
28	Capital Work in Progress (CWIP) - Utility		77,340	35,809	-	-	-	113,150
29	Capital Work in Progress (CWIP) - Non Utility		2,893	3,728	-	-	-	6,620
30	**Capital Work in Progress (CWIP)**		80,233	39,537	-	-	-	119,770
31	**Total Capital Assets**	Sch. 2.1 / 4.2	**5,489,924**	**309,234**	**49,071**	**3,100**	**(0)**	**5,753,187**
32	**Non Utility Assets**		19,110	3,852	713	23	-	**22,272**
33	**Total Utility Capital Assets**		**5,470,814**	**305,382**	**48,358**	**3,078**	**(0)**	**5,730,916**
	Contributions							
34	Utility		785,714	42,875	2,048	279	-	826,819
35	Non Utility		1,422	-	-	-	-	1,422
36	Contributions Work in Progress (KWIP) - Utility		5,896	(5,119)	-	-	-	777
37	Contributions Work in Progress (KWIP) - Non Utility		-	-	-	-	-	-
38	**Total Contributions**	Sch 2.1	**793,031**	**37,756**	**2,048**	**279**	**-**	**829,017**

ATCO Gas
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Depreciation Provision	2021 Retirements	2021 Removals	2021 Salvage	2021 Adjustments	Balance at 12/31/2021
	Distribution								
1	Land		-	-	-	-	-	-	-
2	Land Rights		4,642	526	5	-	-	5	5,168
3	Structures & Improvements		14,060	1,982	368	980	(0)	5	14,700
4	Services & Alterations		757,372	77,939	4,444	11,143	-	(289)	819,436
5	Regulators & Meters		214,601	21,136	1,458	13	-	223	234,489
6	Mains		703,027	63,332	2,671	4,569	61	2,975	762,155
7	Measurement & Regulating Equipment		81,527	8,492	3,328	1,405	(0)	(108)	85,178
8	Meters		98,538	17,911	8,951	-	2,577	-	110,076
9	Renewable Energy		1,279	167	-	-	-	-	1,446
10	**Distribution**		1,875,047	191,485	21,225	18,109	2,638	2,811	2,032,648
	General Plant & Equipment								
11	Franchises		1,093	106	414	-	-	-	785
12	Land		-	-	-	-	-	-	-
13	Structures & Improvements		62,398	4,746	100	413	-	-	66,631
14	**General Plant & Equipment**		63,491	4,852	514	413	-	-	67,416
	Moveable Equipment								
15	Office Furniture & Equipment		10,416	1,080	324	-	-	(6)	11,166
16	Transportation Equipment		46,984	6,399	5,747	34	1,007	-	48,609
17	Heavy Work Equipment		14,075	1,269	1,011	9	219	-	14,543
18	Tools & Work Equipment		11,884	3,007	1,409	-	19	290	13,792
19	Cogeneration Equipment		3,843	26	-	-	-	-	3,869
20	NAIT Fuel Cell		566	-	-	-	-	-	566
21	Communication Equipment		22,585	1,731	1,317	42	-	(11)	22,946
22	Stores, Shop & Lab Equipment		7,753	1,520	856	1	-	-	8,416
23	Electronic Data Processing Equipment		3,126	2,211	397	-	-	16	4,955
24	Base Maps		1,682	(10)	130	-	-	-	1,543
25	Leaseholds		1,976	942	838	12	-	-	2,068
26	Software Development		33,686	12,890	15,304	-	-	-	31,272
27	**Moveable Equipment**		158,576	31,066	27,333	98	1,244	289	163,745
28	**Retirements Work in Progress (RWIP)**		(1,798)	-	-	697	-	-	(2,495)
29	**Total Accumulated Depreciation**	Sch. 2.1 / 4	**2,095,315**	**227,403**	**49,071**	**19,316**	**3,882**	**3,100**	**2,261,314**
30	**Non Utility Assets**		**7,299**	607	713	-	-	-	7,193
36	**Total Utility Accumulated Depreciation**		**2,088,016**	**226,796**	**48,358**	**19,316**	**3,882**	**3,100**	**2,254,121**
	Contributions								
37	Utility		243,376	16,792	2,048	-	-	279	258,398
38	Non Utility		875	31	-	-	-	-	906
39	**Total Contributions**	Sch 2.1 / 4	**244,251**	**16,823**	**2,048**	**-**	**-**	**279**	**259,304**
40	**Net Property, Plant, and Equipment**	Sch. 11	**2,845,829**						**2,922,160**
41	**Net Property, Plant and Equipment (Non-Utility)**	Sch. 11	**(11,264)**						**(14,563)**
42	**Net Property, Plant, and Equipment (Utility)**	Sch. 11	**2,834,564**						**2,907,597**
	Less CWIP & KWIP (Utility)		(71,445)						(112,373)
	Utility Plant in Service		**2,763,120**						**2,795,224**
	Mid Year Utility Plant in Service								**2,779,172**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.

(2) Provide a detailed breakdown of items included in "Other", in a supporting sub-schedule.

(3) Year-end balances for each category must be reconciled on Schedule 11 to the audited Balance Sheet.

ATCO Gas
SUMMARY OF CAPITAL EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Reference	2020 Year End	2021 Year End	Variance 2021 vs. 2020	
	Distribution					
1	Extensions		29,680	31,383	1,703	6%
2	Services		32,359	32,851	492	2%
3	Meters, Regulators and Installations		41,727	46,489	4,762	11%
4	Improvements and MRRP		87,913	114,654	26,741	30%
5	Sub-Total		191,679	225,377	33,698	18%
	Land and Structures					
6	General		3,392	5,738	2,346	69%
	Moveable Equipment					
7	General		15,250	19,957	4,707	31%
8	Communication and Lab Equipment		1,434	1,413	(21)	(1%)
9	Software Development		29,196	56,747	27,550	94%
10	Sub-Total		45,881	78,117	32,237	70%
11	**Capital Expenditures**	Sch. 2.1 / 4.1	**240,952**	**309,233**	**68,281**	**28%**
12	**Capital Expenditures - Non-Utility**		201	3,852	3,651	1821%
13	**Capital Expenditures - Utility**		**240,751**	**305,381**	**64,629**	**27%**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable

(2) Please add line items as needed to give sufficient understanding of the main capital additions in the reporting year.

<u>Variance Explanations</u>

Cross-Ref	
3	**Meters, Regulators and Installations** expenditures were higher mainly due to increased demand for residential meters and increased repair
4	**Improvements and MRRP** expenditures were higher than prior year in steel and plastic mains replacement and Transmission Driven work. This was a ramp up of construction due to the shorter construction season in 2020 due to the pandemic as the replacement programs involve extensive work inside customers homes.
7	**Land and Structures** expenditures were higher due to the purchase of land and a building as well as province wide facility improvements (the installation of energy saving smart equipment).
8	**Moveable Equipment General** expenditures were higher than prior year mainly due to higher purchases of fleet vehicles and higher investment in emergency supply assets.
10	**Software Development** expenditures were higher mainly due to ATCO Gas CIS Replacement Program costs due to increased project activities in 2021 compared to 2020.

ATCO Gas
SUMMARY OF UTILITY INCOME TAX
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Reference	2020 Actual	2021 Actual	Actual vs Actual $	Actual vs Actual %
1	Net Income Before Tax - Fed		140,291	147,487	7,196	5.13%
2	Total Permanent Differences - Fed		(4,417)	(3,900)	517	(11.70%)
3	Total Timing Differences - Fed		(38,784)	(65,267)	(26,483)	68.28%
4	Total Differences - Fed		(43,201)	(69,167)	(25,966)	60.11%
5	Taxable Income - Fed		97,090	78,320	(18,770)	(19.33%)
6	Net Income Before Tax - Prov		140,291	147,487	7,196	5.13%
7	Total Permanent Differences - Prov		(4,417)	(3,900)	517	(11.70%)
8	Total Timing Differences - Prov		(38,667)	(65,258)	(26,591)	68.77%
9	Total Differences - Prov		(43,084)	(69,158)	(26,074)	60.52%
10	Taxable Income - Prov		97,207	78,329	(18,878)	(19.42%)
11	Federal Income Tax Rate		15%	15%		
12	Total Federal Income Tax		14,564	11,748	(2,816)	(19.33%)
13	Provincial Income Tax Rate		9%	8%		
14	Total Provincial Income Tax		8,749	6,266	(2,482)	(28.37%)
15	Current Tax Payable		23,312	18,014	(5,298)	(22.73%)
16	Large Corporation and Other Tax					
17	Prior Year (over)/under provisions		(751)	(4,180)	(3,429)	456.59%
18	Current Year (over)/under provisions				-	N/A
19	Other		351	2,607	2,256	642.74%
20	Current Income Tax		22,912	16,441	(6,471)	(28.24%)
21	Deferred Tax		1,926	3,470	1,544	80.17%
22	Corporate Income Tax		24,838	19,911	(4,927)	(19.84%)
	Income Tax Adjustments					
23	Tax on disallowed O&M					
24	Other					
			-	-	-	N/A
25	Utility Income Tax		24,838	19,911	(4,927)	(19.84%)
26	Effect of Normalization					
27	Utility Income Tax		24,838	19,911	(4,927)	(19.84%)

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.

(2) Describe tax methodology (flow through or based on CICA)

Other Information

ATCO Gas uses a flowthrough tax methodology.

In accordance with Commission Direction 2 in Decision 22570-D01-2018, the unfunded FIT liability is $261.4M for 2021 and $246.8M for 2020.

Variance Explanations

Cross-Ref	
1/6	**Net Income Before Tax -** see Schedule 10.
3/8	**Total Timing Differences** are lower than prior year mainly due to higher immediate deductions relating to capital repairs and maintenance, deductions relating to deferral accounts and higher CCA deducted (partially offset by higher depreciation addback).
17	**Prior Year (over)/under provisions** are lower than prior year mainly due to lower actual filing versus year end provision.
19	**Other** is higher than prior year mainly due to Scientific Research and Experimental Development ITC**.**
21	**Deferred Tax** is higher than prior year mainly due to deferred production abandonment, property tax and load balancing.

SCHEDULE 6

ATCO Gas

SUMMARY OF UTILITY REVENUE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	2021 Normalized vs. Forecast #	2021 Normalized vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	REVENUE CLASSIFICATIONS								
	Residential								
1	Average Number of Customers		1,138,609	1,151,862	1,145,496	6,366	0.56%	13,253	1.16%
2	Revenue		582,186	627,185	625,617	1,568	0.25%	44,999	7.73%
	Commercial (Apartment)								
3	Average Number of Customers		9,295	9,340	9,313	27	0.29%	45	0.48%
4	Revenue		33,431	37,330	37,491	(161)	(0.43%)	3,899	11.66%
	Commercial (Non-Apartment)								
5	Average Number of Customers		91,915	92,681	92,419	262	0.28%	766	0.83%
6	Revenue		196,334	214,813	217,693	(2,880)	(1.32%)	18,479	9.41%
	Industrial								
7	Average Number of Customers		346	343	346	(3)	(0.87%)	(3)	(0.87%)
8	Revenue		12,482	13,384	13,355	29	0.22%	902	7.23%
	Irrigation								
9	Average Number of Customers		384	505	398	107	26.88%	121	31.51%
10	Revenue		330	454	433	21	4.85%	124	37.58%
11	Total Average Number of Customers		1,240,549	1,254,731	1,247,972	6,759	0.54%	14,182	1.14%
12	Sub-Total Rate Revenue	Sch. 1	824,763	893,166	894,589	(1,423)	(0.16%)	68,403	8.29%
	RATE ACCRUALS REVENUE								
13	Rate Accruals Revenue	Sch. 1	34,354	30,390				(3,964)	(11.54%)
	FRANCHISE REVENUE								
14	Franchise Fee Revenue	Sch 1/10	207,262	225,390				18,128	8.75%
	OTHER REVENUE								
15	Other Revenue (Please See Below)	Sch. 1	23,230	22,491				(739)	(3.18%)
16	**TOTAL UTILITY REVENUE**	Sch. 1/10	**1,089,609**	**1,171,437**				**81,828**	**7.51%**

ATCO Gas
SUMMARY OF UTILITY REVENUE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	2021 Normalized vs. Forecast #	2021 Normalized vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	OTHER REVENUE								
17	ATCO Pipelines		16,561	15,215				(1,346)	(8.13%)
18	Other Affiliates		2,065	3,189				1,124	54.43%
19	Facility Repairs		1,324	1,306				(18)	(1.38%)
20	Reinstatement Fees		812	2,209				1,397	172.16%
21	Miscellaneous		2,468	572				(1,896)	(76.81%)
22	Total Other Revenue		**23,230**	**22,491**				**(739)**	**(3.18%)**

Guidelines:
(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.

Note: The 2021 rate revenue forecast is based on the 2021 delivery rates applied to the PBR approved billing determinant forecast.

Revenue Variance Explanations

Cross-Ref	
2	**Residential Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
4	**Commercial (Apartment) Revenue** is higher than prior year primarily due to higher delivery rates in 2021.
6	**Commercial (Non-Apartment) Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
14	**Franchise Revenue** is higher than prior year primarily due to higher delivery rates, cost of gas and number of customers in 2021.
18	**Other Affiliates Revenue** is higher than prior year mainly due to higher affiliate work performed for ATCO Power 2010 and ATCO Corporate Office.
20	**Reinstatement Fees Revenue** is higher than prior year primarily due to a higher number of disconnects/reconnects in 2021.
21	**Other Miscellaneous Revenue** is lower than prior year primarily due to lower secondary services.

ATCO Gas

EXPLANATION OF TRANSACTIONS WITH AFFILIATED COMPANIES

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Affiliate	Nature of Service		2021 Actual
1	**ATCO Ltd. / CUL / CU Inc.**	Rent and Project Services	Revenue	492
2		Administration, Rent and Aircraft	Expenses	(36,781)
3		Licence fees	Expenses	(3,033)
4		Administration, Rent and Aircraft	Capital	(7,612)
5	**ATCO Electric Ltd.**	Rent and Fleet Services	Revenue	1,199
6		Contract Services	Revenue	141
7		Rent and Contractor Services	Expenses	(505)
8		Customer Collections	Expenses	(354)
9		Contract Services	Capital	(971)
10	**ATCO Power 2010**	Contract Services	Revenue	819
11		Contract Services	Expense	(1,619)
12	**ATCO Structures and Logistics**	Rent and Contractor	Expenses	7
13	**ATCO Energy Solutions**	Contract Services	Revenue	201
14	**ATCO Pipelines**	Contract Services	Revenue	15,215
15		Contract Services and Rent	Expenses	(1,636)
16		Transfer of Assets	Capital	2,302
17		Contract Services	Capital	(535)
18	**ATCO Energy**	Contract Services	Revenue	22
19		Contract Services	Expense	(1)
20	**ATCO Infrastructure Solutions Ltd.**	Contract Services	Revenue	157
21	**Northland Utilities Limited - NWT**	Contract Services	Revenue	3
22	**Yukon Electrical**	Contract Services	Revenue	27
23	**Aschor**	Contract Services	Revenue	128

Guidelines:

(1) The services provided or received need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Provide a cross-reference for each item to the relevant schedules where the amounts have been included in this reporting package.
(3) Amounts in this schedule must be reconciled on Schedule 10 to the Audited Financial Statements.
(4) Identify charges in brackets indicating an expense to ABC Utility.

SCHEDULE 8

ATCO Gas

SUMMARY OF PAYROLL AND MANPOWER STATISTICS

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020	%
	Payroll Statistics					
1	Gross Salaries, Wages, & Employee Benefits		196,009	208,724	12,715	6.49%
	Manpower Statistics					
2	Total Regular Employees (FTEs)		1,313	1,303	(10)	(0.78%)
3	Total Temporary Employees (FTEs)		65	117	52	80.00%
4	**Total Manpower**		1,378	1,420	42	3.03%
	Less:					
5	Charged to Non-Regulated		8	2	(6)	(76.38%)
6	**Total Manpower - Utility Operations**		1,370	1,418	48	3.49%
	Manpower Allocation by Division *					
7	Operations		1,224	1,281	57	4.65%
8	Administration		154	139	(15)	(9.91%)
9	**Total Manpower**		1,378	1,420	42	3.03%

Guidelines:

(1) Variance explanations required for $5 million, or 10% or greater and any difference equal to or greater than $1 million.

(2) Please state if FTE is based on an average or upon year end numbers. This should be consistent with the decision.

(3) Add rows as needed to be consistent with the decision.

Variance Explanations

NOTE: Full Time Equivalents (FTEs) are based on year end numbers.

Cross-Ref	
1	2021 Actual is higher than prior year mainly due to lump sum NGEA bargaining and vaccine incentive payments.

ATCO Gas
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	Opening Balance	Adds	Amort.	Recoveries	Ending Balance
Regulatory Accounts							
1	Deferred Supplemental Pension		15,693	(137)			15,556
2	Deferred Post Employment Benefits		42,385	609			42,994
3	Regulatory Income Tax Provision		(701)				(701)
			57,377	**472**	**-**	**-**	**57,849**
Approved Deferral Accounts							
4	Deferred AUC and Intervener Costs		(539)	3,786	3,630	(621)	(1,004)
5	Deferred Consumer Advocate Costs		(579)	888	1,400	334	(757)
6	Deferred Production Abandonments		(317)	3,312	1,400	125	1,720
7	Weather Deferral Account		(2,310)	1,065		10,056	8,811
8	Load Balancing Deferral Account		(3,044)	2,005			(1,039)
9	Transmission Charges		(4,156)	10,105		4,084	10,033
10	Deferred Retailer Payments		1,290			(1,290)	-
			(9,655)	**21,161**	**6,430**	**12,688**	**17,764**
11	**Total Regulatory Accounts**		**47,722**	**21,633**	**6,430**	**12,688**	**75,613**

Guidelines:

(1) The line items should show sufficient breakdown to allow for reasonable understanding of operations. Please state the source of the approved deferral or

(2) Please state the regulated reserve and deferral accounts in this schedule.

Notes:

Cross-Ref	
4	Deferred AUC and Intervener Costs includes AUC administration fees and intervener costs as approved in the Rate Regulation Initiative Decision 2012-237. Amounts collected during the year as approved in Decision 25863-D01-2020.
5	Deferred Consumer Advocate Costs as approved in the Rate Regulation Initiative Decision 2012-237. Amounts collected during the year as approved in Decision 25863-D01-2020.
6	Deferred Production Abandonments as approved in the UADR Decision 2013-417. Amounts collected during the year as approved in Decision 25863-D01-2020.
7	Deferred Weather was approved to continue as a deferral account in the Rate Regulation Initiative Decision 2012-237. The Rider W impacting January 1 to April 30, 2021 was approved in Decision 25666-D01-2020.
8	Load Balancing Deferral Account was approved to continue as a deferral account in the Rate Regulation Initiative Decision 2012-237.
9	Transmission charges collected the amounts approved in Rider T Decision 26378-D01-2021.
10	Deferred Retailer Payments related to deferred payments from retailers as set out in Bulletin 2020-19.

ATCO Gas
RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO ADJUSTED EARNINGS EQUIVALENT
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($000s)

Line No.	Description	Cross-Reference	Adjusted Earnings Equivalent	ASC 980 and Other Reclassification	Normalization of AUC Decisions [1]	2021 Actual	Non-Utility Adjustments	Utility Income	2020 Utility Income	Variance 2021 vs. 2020	
	Revenues										
1	Total Operating Revenue		1,177,122	174	20	1,177,316	(5,879)	1,171,437	1,089,609	81,828	7.51%
2		Sch. 1 / 6	1,177,122	174	20	1,177,316	(5,879)	1,171,437	1,089,609	81,828	7.51%
	Operating Expenses										
3	Operation and Maintenance	Sch. 3	530,476	(305)	-	530,171	(15,719)	514,452	465,516	48,936	10.51%
4	Depreciation and Amortization	Sch. 1 / 4	207,443	31	-	207,474	(575)	206,899	199,937	6,962	3.48%
5	Franchise Fees	Sch. 1 / 6	225,390	-	-	225,390	-	225,390	207,262	18,128	8.75%
6			963,309	(274)	-	963,035	(16,294)	946,741	872,715	74,026	22.74%
	Financing Charges										
7	Interest and Other Expense		72,880	-	-	72,880	(72,880)	-	-	-	N/A
8	Dividends on Equity Preferred Shares		2,989	-	-	2,989	(2,989)	-	-	-	N/A
9	Interest and Other Income		(1,315)	-	-	(1,315)	1,315	-	-	-	N/A
10	Asset Impairment		285	(285)	-	-	-	-	-	-	N/A
11			74,839	(285)	-	74,554	(74,554)	-	-	-	0.00%
12	**Net Earnings Before Tax**		138,974	733	20	139,727	84,969	224,696	216,894	7,802	3.60%
13	**Income Tax**	Sch. 1 / 5	17,509	174	5	17,516	2,224	19,911	24,838	(4,927)	(19.84%)
14	**Return**	Sch. 1 / 2	121,465	559	15	122,211	82,745	204,785	192,056	12,729	6.63%

1) Mainly reflects Decision 24188-D02-2020.

ATCO Gas
RECONCILIATION OF ADJUSTED EARNINGS EQUIVALENT TO AUDITED FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($000s)

Line No.	Description	Audited Financial Statements	Regulatory Accounts	Contributions Reclass	O&M Reclass	Pension, OPEB, Vacation	Other Fixed Asset Adjustments	AFUDC/ IDC	ASC 980 Impairment	Dividends on Preferred Shares	Future Income Tax	Adjusted Earnings Equivalent
	Revenues											
1	Total Operating Revenue	1,147,669	46,276	(16,823)	-	-	-	-	-	-	-	1,177,122
2		1,147,669	46,276	(16,823)	-	-	-	-	-	-	-	1,177,122
	Operating Expenses											
3	Salaries, Wages and Benefits	99,605	-	-	(99,605)	-	-	-	-	-	-	-
4	Plant and Equipment Maintenance	64,120	-	-	(64,120)	-	-	-	-	-	-	-
5	Energy Transmission and Transportation	265,821	-	-	(265,821)	-	-	-	-	-	-	-
6	Operation and Maintenance	-	(19,436)	-	548,682	1,230	-	-	-	-	-	530,476
7	Depreciation and Amortization	144,180	79,984	(16,823)	-	-	279	-	(177)	-	-	207,443
8	Franchise Fees	225,390	-	-	-	-	-	-	-	-	-	225,390
9	Property Taxes	626	-	-	(626)	-	-	-	-	-	-	-
10	Other Expenses	118,510	-	-	(118,510)	-	-	-	-	-	-	-
11		918,252	60,548	(16,823)	-	1,230	279	-	(177)	-	-	963,309
12	Operating Profit	229,417	(14,272)	-	-	(1,230)	(279)	-	177	-	-	213,813
	Financing Charges											
13	Interest Income	(312)	(1,003)	-	-	-	-	-	-	-	-	(1,315)
14	Interest and Other Expense	77,190	(2,012)	-	-	-	-	(2,298)	-		-	72,880
15	Dividends on Equity Preferred Shares	-	-	-	-	-	-	-	-	2,989	-	2,989
16	Asset Impairment	-	-	-	-	-	-	-	285	-	-	285
17		76,878	(3,015)	-	-	-	-	(2,298)	285	2,989	-	74,839
18	**Earnings Before Income Taxes**	152,539	(11,257)	-	-	(1,230)	(279)	2,298	(108)	(2,989)	-	138,974
19	**Income Tax**	36,741	-	-	-	-	-	-	-	-	(19,232)	17,509
20	**Earnings**	115,798	(11,257)	-	-	(1,230)	(279)	2,298	(108)	(2,989)	19,232	121,465

ATCO Gas

RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO ADJUSTED EARNINGS EQUIVALENT

FOR THE YEAR ENDED DECEMBER 31, 2021

BALANCE SHEET ITEMS

($000s)

Line No.	Description	Cross-Reference	Adjusted Earnings Equivalent	ASC 980 and Other Reclassification	Adjustments	Utility Total	2021 Financial Results Distribution	Retail	Other	Total
	Assets									
	Current Assets									
1	Cash		-	-	-	-	-	-	-	-
2	Accounts Receivable		357,593	-	-	357,593	357,593	-	-	357,593
3	Inventories		1,364	-	-	1,364	1,364	-	-	1,364
4	Accounts Receivable from Parent and Affiliated Corporations		5,069	-	-	5,069	5,069	-	-	5,069
5	Current Regulatory Assets	Sch. 9	15,579	(3,826)	-	11,753	11,753	-	-	11,753
6	Prepaid Expenses		3,535	-	-	3,535	3,535	-	-	3,535
7	**Total Current Assets**		383,140	(3,826)	-	379,314	379,314	-	-	379,314
8	Property Plant and Equipment	Sch. 4.1	3,186,533	(264,373)	(14,563)	2,907,597	2,907,597	-	14,563	2,922,160
9	Intangible Assets		170,050	(170,050)		-	-	-	-	-
10	Regulatory Assets	Sch. 9	293,016	(225,655)		67,361	67,361	-	-	67,361
11	Other Assets		21,707			21,707	21,707	-	-	21,707
12	**Total Assets**		**4,054,446**	**(663,904)**	**(14,563)**	**3,375,979**	**3,375,979**	**-**	**14,563**	**3,390,542**
	Liabilities									
	Current Liabilities									
13	Bank Indebtedness		122,203	-	-	122,203	122,203	-	-	122,203
14	Accounts Payable and Accrued Liabilities		280,334	(3,826)	-	276,508	276,508	-	-	276,508
15	Accounts Payable to Parent and Affiliated Corporations		34,660	-	-	34,660	34,660	-	-	34,660
16	Current Regulatory Liabilities	Sch. 9	1,762	-		1,762	1,762	-	-	1,762
17	**Total Current Liabilities**		438,959	(3,826)	-	435,133	435,133	-	-	435,133
18	Deferred Income Tax Liabilities		265,691	(260,918)	-	4,773	4,773	-	-	4,773
19	Regulatory Liabilities	Sch. 9	425,053	(423,313)	-	1,740	1,740	-	-	1,740
20	Retirement Benefit Obligations		58,550	-	-	58,550	58,550	-	-	58,550
21	Deferred Credits		(1,121)	-	-	(1,121)	(1,121)	-	-	(1,121)
22	Long Term Debt	Sch. 2.3	1,754,629	-	(8,779)	1,745,850	1,745,850	-	8,779	1,754,629
23	Equity Preferred Shares	Sch. 2.4	65,500	-	(395)	65,105	65,105	-	395	65,500
24	**Total Liabilities**		3,007,261	(688,057)	(9,175)	2,310,029	2,310,029	-	9,175	2,319,204
	Equity									
25	Class A and B Shares		119,107	-	-	119,107	119,107	-	-	119,107
26	Retained Earnings		928,078	24,153	(5,388)	946,843	946,843	-	5,388	952,231
27	**Total Equity**		1,047,185	24,153	(5,388)	1,065,950	1,065,950	-	5,388	1,071,338
28	**Total Liabilities and Equity**		**4,054,446**	**(663,904)**	**(14,563)**	**3,375,979**	**3,375,979**	**-**	**14,563**	**3,390,542**

Note

1.In 2021, the International Financial Reporting Interpretations Committee (IFRIC) of the International Accounting Standards Board (IASB) published guidance regarding the accounting for costs incurred in implementing cloud computing arrangements. The IFRIC specifically addresses how to account for costs of configuring or customizing a supplier's application software in a Software as a Service (SaaS) arrangement. The IFRIC concluded that these costs should be expensed, given the software being configured or customized is not owned or controlled by the customer. Implementation of the IFRIC guidance was required to be implemented by December 31, 2021 and applied retroactively. Note that no similar guidance exists in US GAAP resulting in different accounting results for many Alberta peer utilities reporting under US GAAP.

2.ATCO Gas examined this issue and determined that approximately 2 percent of the ATCO Gas SaaS arrangement costs were impacted. However, given that the impact of this IFRIC guidance is negligible for rate base (the cumulative impact of approximately $2.3 million of ATCO Gas' $2.8 billion rate base), ATCO Gas continues to reflect costs of SaaS arrangements in this COS consistent with other Alberta Utilities reporting in US GAAP.

ATCO Gas
RECONCILIATION OF ADJUSTED EARNINGS EQUIVALENT TO AUDITED FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2021
BALANCE SHEET ITEMS
($000s)

Line No.	Description	Audited Financial Statements	Regulatory Assets / Liabilities	Preferred Share Reclass	Contributions	Debt Expense Amortized	Fixed Asset Adjustments	Adjusted Earnings Equivalent
	Assets							
	Current Assets							
1	Cash	-	-	-	-	-	-	-
2	Accounts Receivable	274,610	79,645	-	3,338	-	-	357,593
3	Inventories	1,364	-	-	-	-	-	1,364
4	Accounts Receivable from Parent and Affiliated Corporations	5,069	-	-	-	-	-	5,069
5	Current Regulatory Assets	-	15,579	-	-	-	-	15,579
6	Prepaid Expenses	3,535	-	-	-	-	-	3,535
7	**Total Current Assets**	284,578	95,224	-	3,338	-	-	383,140
8	Property Plant and Equipment	3,960,655	-	-	(569,616)	-	(204,506)	3,186,533
9	Intangible Assets	170,771	-	-	(99)	-	(622)	170,050
10	Regulatory Assets	-	293,016	-	-	-		293,016
11	Other Assets	13,298	998	-	-	9,843	(2,432)	21,707
12	**Total Assets**	**4,429,302**	**389,238**	**-**	**(566,377)**	**9,843**	**(207,560)**	**4,054,446**
	Liabilities							
	Current Liabilities							
13	Bank Indebtedness	122,203	-	-	-	-	-	122,203
14	Accounts Payable and Accrued Liabilities	280,334	-	-	-	-	-	280,334
15	Accounts Payable to Parent and Affiliated Corporations	34,660	-	-	-	-	-	34,660
16	Current Regulatory Liabilities	-	1,762	-	-	-	-	1,762
17	**Total Current Liabilities**	437,197	1,762	-	-	-	-	438,959
18	Deferred Income Tax Liabilities	308,379	(42,688)	-	-	-	-	265,691
19	Regulatory Liabilities	-	425,053	-	-	-	-	425,053
20	Retirement Benefit Obligations	78,289	(19,739)	-	-	-	-	58,550
21	Long Term Debt	1,744,786	-	-	-	9,843	-	1,754,629
22	Other Liabilities	567,858	-	-	(566,438)	-	(2,541)	(1,121)
23	Equity Preferred Shares	-	-	65,500	-	-	-	65,500
24	**Total Liabilities**	3,136,509	364,388	65,500	(566,438)	9,843	(2,541)	3,007,261
	Equity							
25	Equity Preferred Shares	64,273	-	(64,273)	-	-	-	-
26	Class A and B Shares	119,107	-	-	-	-	-	119,107
27	Retained Earnings	1,109,413	24,850	(1,227)	61	-	(205,019)	928,078
28	**Total Equity**	1,292,793	24,850	(65,500)	61	-	(205,019)	1,047,185
29	**Total Liabilities and Equity**	**4,429,302**	**389,238**	**-**	**(566,377)**	**9,843**	**(207,560)**	**4,054,446**

ATCO Gas
SCHEDULE OF PENSION PLAN CONTRIBUTIONS
FOR THE YEAR ENDED DECEMBER 31, 2021
($Millions)

Line No.

ATCO Gas has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

2021 Actual

Line No.		Defined Benefit Pension Expense		Defined Contribution Pension Expense	Total
		Service Amount	Special Payment	Service Amount	
1	**ATCO Gas** (Note 1)	4.5	-	7.2	**11.7**
2	**ATCO Unregulated**	2.5	-	6.1	**8.6**

Note 1 - The actual defined benefit pension expense, special payment and defined contribution service amount do not include amounts allocated from the ATCO Head Office. This amount includes COLA at 100%.

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision.

Under Performance Based Regulation, ATCO Gas no longer has deferral account treatment for special payment pension contributions.

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2020 CU Pension Plan Report dated August 11, 2021 was filed with the Superintendent of Pensions. The required pension funding contributions for ATCO Gas beginning January 1, 2021 is $4.5 million for current service.

ATCO Gas (North)
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	Cross Ref.	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $
1	Debt (Deemed)		925,329	60.29%	925,329	4.48%	41,496
2	Preferred Shares		41,668	2.71%	41,668	3.65%	1,522
3	Common Equity		567,921	37.00%	567,921	12.77%	72,548
4	Mid-Year Invested Capital		1,534,918	100.00%	1,534,918		
5	Return on Rate Base	Sch. 10				**7.529%**	**115,566**
6	No Cost Capital		-				
7	Total Mid-Year Rate Base	Sch. 2.1	**1,534,918**				

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) Provide the breakdown of the items making up the difference (including disallowed items etc.).
(3) Common equity is based on the approved equity ratio.
(4) Please complete these schedules using the approved deemed capital structure.
(5) The cost rate for the common equity should be inferred from the return and prorated rate base of common equity.

SCHEDULE 2.1

ATCO Gas (North)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Property, Plant and Equipment - Utility					
1	Opening Balance		2,935,356	2,962,504	27,148	0.92%
2	Expenditures	Sch. 4.1 / 4.2	131,480	167,030	35,551	27.04%
3	Retirements	Sch. 4.1	(102,694)	(26,977)	75,718	(73.73%)
4	Transfers and Adjustments		(1,637)	3,071	4,708	(287.58%)
5	Closing Balance	Sch. 4.1	2,962,504	3,105,629	143,125	4.83%
6	**Mid-Year Property, Plant and Equipment**		2,948,930	3,034,067	85,137	2.89%
	Accumulated Depreciation - Utility					
7	Opening Balance		1,105,138	1,136,214	31,077	2.81%
8	Depreciation Expense	Sch. 4	137,607	121,653	(15,953)	(11.59%)
9	Retirements	Sch. 4.1	(102,694)	(26,977)	75,718	(73.73%)
10	Proceeds from Disposals of Capitalized Assets	Sch. 4.1	1,914	2,559	645	33.70%
11	Removal, Depreciation Capitalized and Other Transfers		(5,750)	(6,135)	(386)	6.71%
12	Closing Balance	Sch. 4.1	1,136,214	1,227,315	91,100	8.02%
13	**Mid-Year Accumulated Depreciation**		1,120,676	1,181,764	61,088	5.45%
	Contributions in Aid of Construction - Utility					
14	Opening Balance		(410,906)	(425,682)	(14,775)	3.60%
15	Closing Balance	Sch. 4.1	(425,682)	(446,426)	(20,744)	4.87%
16	**Mid-Year Contributions in Aid of Construction**		(418,294)	(436,054)	(17,760)	4.25%
	Amortization of Contributions - Utility					
17	Opening Balance		116,290	125,423	9,133	7.85%
18	Closing Balance	Sch. 4.1	125,423	134,452	9,029	7.20%
19	**Mid-Year Amortization of Contributions**		120,856	129,937	9,081	7.51%
20	Less: Construction Work in Progress (CWIP) - Mid-Year		(46,227)	(51,112)	(4,885)	10.57%
21	Less: Contributions Work in Progress (KWIP) - Mid-Year		1,890	2,091	200	10.60%
22	**Construction Work in Progress (CWIP) - Mid-Year**		(44,336)	(49,021)	(4,685)	10.57%
23	**Mid-Year Utility Plant in Service**		1,486,480	1,497,164	10,684	0.72%
		Should be	1,461,826	(24,654)		
	Necessary Working Capital					
24	Cash Expenses		(384)	1,609	1,993	(519.01%)
25	Materials and Supplies		1,776	1,770	(6)	(0.34%)
26	Prepayments and Deferrals		15,323	29,197	13,874	90.54%
27	Financial Items		2,535	4,944	2,409	95.03%
28	Goods and Services Tax (GST)		(43)	234	277	(644.19%)
			19,207	37,754	18,547	96.56%
29	**Mid-Year Rate Base**	Sch. 2	**1,505,687**	**1,534,918**	**29,231**	**1.94%**

ATCO Gas (North)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) If there was a negotiated settlement in place for the reporting year please state the approved negotiated settlement numbers in the decision colum
(3) Please note the source of the numbers in the decision or negotiated settlement as applicable.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2018, 2019 and 2020.

Variance Explanations

Cross-Ref	
2	**Expenditures** refer to Schedule 4.2.
3/9	**Retirements** are lower than prior year mainly due to Decision 24188-D02-2020 which approved the use of amortization accounting for a number of accounts including Software and Leasehold Improvements resulting in retirements for balances older than the approved amortization period in 2020.
4	**Adjustments and Transfers** are higher than prior year mainly due to asset transfers between ATCO Pipelines and ATCO Gas associated with the Urban Pipelines Replacement (UPR) Program.
8	**Depreciation Expense** refer to Schedule 4.0.
20	**Construction Work in Progress (CWIP)** is higher than prior year primarily due to IT projects as a result of the continued work on the ATCO Gas CIS Replacement Program.
24	**Cash Expenses** are higher mainly due to income taxes and higher operation and maintenance.
26	**Prepayments and Deferrals** are higher than the prior year mainly due to the outstanding collection resulting from the implementation of approved depreciation parameters as per Decision 24188-D02-2020.
27	**Financial Items** are higher than the prior year mainly due to lower dividends.

ATCO Gas (North)

SUMMARY OF DEGREE DAYS & YEAR END CUSTOMERS AND THROUGHPUT

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Actual vs. Forecast #	Variance 2021 Actual vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
1	10 Year Average Normal Degree Days	4,284	4,268	4,268	-	0.00%	(16)	(0.37%)
	Number of Year-End Customers							
2	Residential	572,147	579,002	575,512	3,490	0.61%	6,855	1.20%
3	Commercial	57,477	57,837	57,738	99	0.17%	360	0.63%
4	Industrial	154	153	155	(2)	(1.29%)	(1)	(0.65%)
5	Total Customers	629,778	636,992	633,405	3,587	0.57%	7,214	1.15%
	Normalized Throughput - TJs							
6	Residential	64,106	64,744	63,876	868	1.36%	638	1.00%
7	Commercial	68,756	69,366	70,120	(754)	(1.08%)	610	0.89%
8	Industrial	4,680	5,050	5,235	(185)	(3.53%)	370	7.91%
9	Total Normalized Throughput	137,542	139,160	139,231	(71)	(0.05%)	1,618	1.18%

Note:

The 2020 throughput is normalized based on the ten year average temperatures ending 2018.

The 2021 throughput is normalized based on the ten year average temperatures ending 2019.

The 2021 customers and throughput forecasts are based on AUC Decision 25863-D01-2020.

In Decision 20820-D01-2015, the Commission directed in subsequent PBR annual rate adjustment filings to provide information on the variance from forecast to actual billing determinants in each completed prior year of the PBR term, as well as identify drivers behind a variance larger than ±5 per cent on an annual basis.

SCHEDULE 3

ATCO Gas (North)

SUMMARY OF OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Operating & Maintenance Expense					
1	Gas Management		309	302	(6)	(2.04%)
2	Transmission		112,717	133,415	20,698	18.36%
3	Distribution		59,203	71,572	12,369	20.89%
4	General		4,825	5,179	355	7.35%
5	Sales and Transportation Promotion		4,994	1,822	(3,172)	(63.52%)
6	Customer Accounting		7,269	8,244	975	13.41%
7	Administration and General		60,563	54,712	(5,852)	(9.66%)
8	**Total Operating & Maintenance Expense**		249,879	275,245	25,366	10.15%
9	Less: Non-Utility O&M		9,698	8,193	(1,504)	(15.51%)
10	**Operating & Maintenance Expense - Net**	Sch. 10	240,181	267,052	26,870	11.19%

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) Global reductions refers to the reduction of fees chargeable as deemed in the rate application decision.
(3) Please add line items as needed to more clearly identify major O&M expenses.

Variance Explanations

Cross - Ref	
2	**Transmission** costs are higher than prior year mainly due to an increase in rates.
3	**Distribution** costs are higher than prior year mainly due to increased volumes in operational maintenance and customer services as well as lump sum NGEA bargaining payouts.
5	**Sales and Transportation Promotion** costs are lower than prior year mainly due a decrease in non-utility sales**.**
6	**Customer Accounting** costs are higher than prior year mainly due to higher volume in customer cutoffs for non-payment.
7	**Administration and General** costs are lower than prior year mainly due to lower IT transition costs associated with the re-alignment of IT services.
9	**Non-Utility O&M** costs are lower than prior year mainly due a decrease in non-utility sales, partially offset by an increase in sponsorships and donations.

SCHEDULE 4

ATCO Gas (North)
SUMMARY OF DEPRECIATION
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Depreciation Expense					
1	Distribution Plant		100,696	104,287	3,591	3.57%
2	General Plant		18,611	19,414	803	4.32%
3	Sub-total	Sch. 4.1	119,307	123,701	4,394	3.68%
4	Less: Capitalized Depreciation		(2,322)	(2,559)	(238)	10.23%
5	Sub-total		116,985	121,142	4,157	3.55%
6	Non-Utility Depreciation	Sch. 4.1	(244)	(265)	(20)	8.27%
7	**Utility Depreciation Expense**	Sch. 2.1	116,741	120,878	4,137	
8	Amortization of Contributions	Sch. 4.1	(9,509)	(9,869)	(360)	3.79%
9	Non-Utility Amortization of Contributions	Sch. 4.1	10	10	(0)	(0.74%)
10	**Amortization of Contributions - Utility**		(9,499)	(9,860)	(360)	3.79%
	Other					
11	Production Abandonments		700	700	-	0.00%
12	**Total Utility Depreciation Expense**	Sch. 10	**107,942**	**111,718**	**3,776**	**3.50%**

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2020 only.

Variance Explanations

Cross-Ref	
1	Distribution Plant is higher than the prior year due to a higher opening depreciable base as well as an increase in depreciation resulting from 2021 capital additions.

ATCO Gas (North)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
	Distribution							
1	Land		3,488	619	-	-	-	4,107
2	Land Rights		29,610	2,616	5	11	(22)	32,211
3	Structures & Improvements		34,059	1,738	333	10	(18)	35,457
4	Services & Alterations		961,945	32,450	2,871	-	(2,698)	988,825
5	Regulators & Meters		280,159	7,377	928	-	92	286,699
6	Mains		1,076,652	49,760	1,291	2,963	31	1,128,115
7	Measurement & Regulating Equipment		113,237	16,771	2,196	109	(83)	127,839
8	Meters		140,544	13,764	4,939	-	-	149,369
9	Renewable Energy		962	-	-	-	-	962
10	**Distribution**		2,640,656	125,094	12,562	3,094	(2,698)	2,753,584
	General Plant & Equipment							
11	Franchises		578	-	364	-		213
12	Land		8,369	-	-	-		8,369
13	Structures & Improvements		83,339	694	100	-		83,932
14	Interco Contributions		242	-	-	-		242
15	**General Plant & Equipment**		92,528	694	465	-	-	92,757
	Moveable Equipment							
16	Office Furniture & Equipment		12,808	102	75	-	(18)	12,817
17	Transportation Equipment		53,021	2,797	3,023	-	-	52,795
18	Heavy Work Equipment		15,075	672	715	-	-	15,032
19	Tools & Work Equipment		18,171	1,293	870	-	2,701	21,295
20	Cogeneration Equipment		3,060	8	-	-	-	3,067
21	Communication Equipment		21,639	833	797	-	(142)	21,533
22	Stores, Shop Equipment & Lab Equipment		17,162	1,147	484	-	-	17,825
23	Leasehold Improvements		1,947	148	41	-	-	2,054
24	Electronic Data Processing Equipment		3,631	2,937	208	-	156	6,516
25	Base Maps		1,136	-	92	-	-	1,044
26	Software Development		48,387	12,151	7,645	-	-	52,893
27	**Moveable Equipment**		196,036	22,088	13,950	-	2,698	206,873
28	Capital Work in Progress (CWIP) - Utility		41,504	19,215				60,719
29	Capital Work in Progress (CWIP) - Non Utility		1,926	3,792				5,718
30	**Capital Work in Progress (CWIP)**		43,430	23,006				66,437
31	**Total Capital Assets**	Sch. 2.1 / 4.2	**2,972,650**	**170,882**	**26,977**	**3,094**	**(0)**	**3,119,650**
32	**Non-Utility Assets**		**10,146**	3,852	-	23		**14,021**
33	**Total Utility Capital Assets**		**2,962,504**	**167,030**	**26,977**	**3,071**	**(0)**	**3,105,629**
	Contributions							
34	Utility		421,984	24,790	1,109	279	-	445,943
35	Non-Utility		665	-	-	-	-	665
36	Contributions Work in Progress (KWIP) - Utility		3,698	(3,215)	-	-	-	483
37	Contributions Work in Progress (KWIP) - Non Utility							
38	**Total Contributions**	Sch 2.1	**426,347**	**21,575**	**1,109**	**279**	**-**	**447,091**

ATCO Gas (North)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Depreciation Provision	2021 Retirements	2021 Removals	2021 Salvage	2021 Adjustments	Balance at 12/31/2021
	Distribution								
1	Land		-	-	-	-	-	-	-
2	Land Rights		4,281	412	5	-	-	5	4,693
3	Structures & Improvements		7,649	1,084	333	766	-	9	7,643
4	Services & Alterations		446,316	45,924	2,871	6,126	-	(251)	482,993
5	Regulators & Meters		125,812	11,604	928	8	-	13	136,494
6	Mains		334,942	31,968	1,291	2,322	49	2,970	366,316
7	Measurement & Regulating Equipment		43,145	4,339	2,196	809	-	97	44,575
8	Meters		57,642	8,916	4,939	-	1,760	-	63,379
9	Renewable Energy		274	40	-	-	-	-	314
10	**Distribution**		1,020,061	104,287	12,562	10,031	1,809	2,843	1,106,406
	General Plant & Equipment								
11	Franchises		537	37	364	-	-	-	210
12	Land		-	-	-	-	-	-	-
13	Structures & Improvements		33,317	2,656	100	261	-	-	35,612
14	**General Plant & Equipment**		33,854	2,693	465	261	-	-	35,822
	Moveable Equipment								
15	Office Furniture & Equipment		6,603	642	75	-	-	(3)	7,167
16	Transportation Equipment		25,982	3,632	3,023	22	562	-	27,131
17	Heavy Work Equipment		8,599	720	715	9	178	-	8,775
18	Tools & Work Equipment		7,622	1,793	870	-	10	252	8,807
19	Cogeneration Equipment		2,720	18	-	-	-	-	2,737
20	NAIT Fuel Cell		566	-	-	-	-	-	566
21	Communication Equipment		11,394	1,003	797	21	-	(5)	11,574
22	Stores, Shop & Lab Equipment		3,522	950	484	-	-	-	3,989
23	Electronic Data Processing Equipment		1,293	1,062	208	-	-	7	2,154
24	Base Maps		1,135	0	92	-	-	-	1,044
25	Leaseholds & Improvements		732	484	41	9	-	-	1,166
26	Software Development		16,642	6,417	7,645	-	-	-	15,414
27	**Moveable Equipment**		86,813	16,721	13,950	61	750	251	90,525
28	**Retirements Work in Progress (RWIP)**		(409)			659			(1,068)
29	**Total Accumulated Depreciation**	Sch. 2.1 / 4	**1,140,319**	**123,701**	**26,977**	**11,013**	**2,559**	**3,094**	**1,231,684**
30	**Non-Utility Assets**		**4,105**	265	-				**4,369**
31	**Total Utility Accumulated Depreciation**		**1,136,215**	**123,437**	**26,977**	**11,013**	**2,559**	**3,094**	**1,227,315**
				1,136,215					
	Contributions								
32	Utility		125,423	9,860	1,109	-	-	279	134,452
33	Non-Utility		480	10	-	-	-	-	489
34	**Total Contributions**	Sch 2.1 / 4	**125,902**	**9,869**	**1,109**	**-**	**-**	**279**	**134,941**
35	**Net Property, Plant, and Equipment**		**1,531,886**						**1,575,816**
36	**Net Property, Plant and Equipment (Non-Utility)**		**(5,856)**						**(9,476)**
37	**Net Property, Plant, and Equipment (Utility)**		**1,526,030**						**1,566,340**
	Less CWIP & KWIP (Utility)		(37,806)						(60,236)
	Utility Plant in Service		**1,488,224**						**1,506,104**
	Mid Year Utility Plant in Service								**1,497,164**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Provide a detailed breakdown of items included in "Other", in a supporting sub-schedule.
(3) Year-end balances for each category must be reconciled on Schedule 11 to the audited Balance Sheet.

SCHEDULE 4.2

ATCO Gas (North)

SUMMARY OF CAPITAL EXPENDITURES

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross- Reference	2020 Year End	2021 Year End	Variance 2021 vs. 2020	
	Distribution					
1	Extensions		14,278	15,500	1,222	8.56%
2	Services		18,290	17,900	(390)	(2.13%)
3	Meters, Regulators and Installations		22,236	26,254	4,018	18.07%
4	Improvements and MRRP		50,195	65,523	15,328	30.54%
5	Sub-Total		105,000	125,178	20,178	19.22%
	Land and Structures					
6	General		2,485	3,488	1,003	40.37%
	Moveable Equipment					
7	General		9,207	12,826	3,619	39.31%
8	Communication and Lab Equipment		818	1,057	239	29.22%
9	Software Development		14,170	28,332	14,162	99.94%
10	Sub-Total		24,195	42,216	14,401	59.52%
11	**Capital Expenditures**	Sch. 2.1 / 4.1	**131,680**	**170,881**	**39,201**	**29.77%**
12	**Capital Expenditures - Non-Utility**		201	3,852	3,651	1820.82%
13	**Capital Expenditures - Utility**		**131,480**	**167,029**	**35,550**	**27.04%**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Please add line items as needed to give sufficient understanding of the main capital additions in the reporting year.

Variance Explanations

Cross-Ref	
3	**Meters, Regulators and Installations** higher due mainly to increased demand for residential meters & increased repair costs.
4	**Improvements and MRRP** expenditures were higher than prior year in steel and plastic mains replacement and Transmission Driven work. This was a ramp up of construction due to the shorter construction season in 2020 due to the pandemic as the replacement programs involve extensive work inside customers homes.
7	**Land and Structures** expenditures were higher due to the purchase of land and a building.
8	**Moveable Equipment General** expenditures were higher than prior year mainly due to higher purchases of fleet vehicles and higher investment in emergency supply assets.
10	**Software Development** higher ATCO Gas CIS Replacement Program costs due to increased project activities in 2021 compared to 2020.

ATCO Gas (North)
SUMMARY OF UTILITY REVENUE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Act vs. Forecast #	Variance 2021 Act vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	REVENUE CLASSIFICATIONS								
	Residential								
1	Average Number of Customers		568,863	575,012	572,291	2,721	0.48%	6,149	1.08%
2	Revenue		302,840	324,147	322,539	1,608	0.50%	21,307	7.04%
	Commercial (Apartment)								
3	Average Number of Customers		5,726	5,759	5,730	29	0.51%	33	0.58%
4	Revenue		20,868	23,316	23,353	(37)	(0.16%)	2,448	11.73%
	Commercial (Non-Apartment)								
5	Average Number of Customers		51,431	51,753	51,686	67	0.13%	322	0.63%
6	Revenue		108,019	116,519	117,866	(1,347)	(1.14%)	8,500	7.87%
	Industrial								
7	Average Number of Customers		155	153	155	(2)	(1.29%)	(2)	(1.29%)
8	Revenue		5,564	5,933	5,865	68	1.16%	369	6.63%
9	Total Average Number of Customers		626,175	632,677	629,862	2,815	0.45%	6,502	1.04%
10	Sub-Total Rate Revenue		437,291	469,915	469,623	292	0.06%	32,624	7.46%
	RATE ACCRUALS REVENUE								
11	Rate Accruals Revenue		17,845	21,709				3,864	21.65%
	FRANCHISE REVENUE								
12	Franchise Fee Revenue		129,892	135,255				5,363	4.13%
	OTHER REVENUE								
13	Other Revenue (Please See Below)		14,342	13,889				(454)	(3.16%)
14	**TOTAL UTILITY REVENUE**	Sch 10	**599,370**	**640,768**				**41,397**	6.91%

ATCO Gas (North)
SUMMARY OF UTILITY REVENUE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Act vs. Forecast #	Variance 2021 Act vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	OTHER REVENUE								
15	ATCO Pipelines		10,457	9,330				(1,127)	(10.78%)
16	Other Affiliates		1,577	2,427				850	53.93%
17	Facility Repairs		614	603				(12)	(1.89%)
18	Reinstatement Fees		406	1,105				699	172.16%
19	Miscellaneous		1,288	424				(864)	(67.06%)
20	Total Other Revenue		14,342	13,889				(454)	(3.16%)

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.

Note: The 2021 rate revenue forecast is based on the 2021 delivery rates applied to the PBR approved billing determinant forecast.

Revenue Variance Explanations

Cross-Ref	
2	**Residential Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
4	**Commercial (Apartment) Revenue** is higher than prior year primarily due to higher delivery rates in 2021.
6	**Commercial (Non-Apartment) Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
12	**Franchise Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
15	**ATCO Pipelines Revenue** is lower than prior year mainly due to lower transmission field services.
16	**Other Affiliates Revenue** is higher than prior year mainly due to higher affiliate work performed for ATCO Power 2010 and ATCO Corporate Office.
18	**Reinstatement Fees Revenue** is higher than prior year primarily due to a higher number of disconnects/reconnects in 2021.
19	**Other Miscellaneous Revenue** is lower than prior year primarily due to lower secondary services.

ATCO Gas (North)
UTILITY INCOME
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($000s)

Line No.	Description	Cross-Reference	2021 Utility Total	2020 Utility Total	Variance 2021 vs. 2020	
	Revenues					
1	Total Operating Revenue		640,768	599,370	41,397	6.91%
2		Sch. 6	640,768	599,370	41,397	6.91%
	Operating Expenses					
3	Operation and Maintenance (including property tax)		267,478	240,578	26,899	11.18%
4	Depreciation and Amortization	Sch. 4	111,718	107,942	3,776	3.50%
5	Franchise Fees	Sch. 6	135,255	129,892	5,363	4.13%
6			514,451	478,412	36,038	18.81%
7	**Income Tax**		10,751	13,410	(2,659)	(19.83%)
8	**Utility Income**	Sch. 2	**115,566**	**107,548**	**8,018**	**7.46%**

ATCO Gas (South)
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross Ref.	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $
1	Debt (Deemed)		796,376	60.29%	796,376	4.48%	35,713
2	Preferred Shares		35,862	2.71%	35,862	3.65%	1,310
3	Common Equity		488,777	37.00%	488,777	10.68%	52,197
4	Mid-Year Invested Capital		1,321,015	100.00%	1,321,015		
5	Return on Rate Base	Sch. 10				**6.754%**	**89,220**
6	No Cost Capital		701				
7	Total Mid-Year Rate Base	Sch. 2.1	**1,321,716**				

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) Provide the breakdown of the items making up the difference (including disallowed items etc.).
(3) Common equity is based on the approved equity ratio.
(4) Please complete these schedules using the approved deemed capital structure.
(5) The cost rate for the common equity should be inferred from the return and prorated rate base of common equity.

SCHEDULE 2.1

ATCO Gas (South)

SUMMARY OF MID-YEAR RATE BASE

FOR THE YEAR ENDED DECEMBER 31, 2021

($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	%
	Property, Plant and Equipment - Utility					
1	Opening Balance		2,495,730	2,508,310	12,580	0.50%
2	Expenditures	Sch. 4.1 / 4.2	109,272	138,351	29,079	26.61%
3	Retirements	Sch. 4.1	(95,244)	(21,382)	73,862	(77.55%)
4	Transfers and Adjustments		(1,448)	7	1,455	(100.45%)
5	Closing Balance	Sch. 4.1	2,508,310	2,625,287	116,976	4.66%
6	**Mid-Year Property, Plant and Equipment**		2,502,020	2,566,798	64,778	2.59%
	Accumulated Depreciation - Utility					
7	Opening Balance		936,647	951,803	15,156	1.62%
8	Depreciation Expense	Sch. 4	115,793	101,413	(14,380)	(12.42%)
9	Retirements	Sch. 4.1	(95,244)	(21,382)	73,862	(77.55%)
10	Proceeds from Disposals of Capitalized Assets		1,070	1,324	253	23.66%
11	Removal, Depreciation Capitalized and Other Transfers		(6,464)	(6,352)	112	(1.73%)
12	Closing Balance	Sch. 4.1	951,803	1,026,806	75,003	7.88%
13	**Mid-Year Accumulated Depreciation**		944,225	989,304	45,080	4.77%
	Contributions in Aid of Construction - Utility					
14	Opening Balance		(356,239)	(365,927)	(9,688)	2.72%
15	Closing Balance	Sch. 4.1	(365,927)	(381,169)	(15,242)	4.17%
16	**Mid-Year Contributions in Aid of Construction**		(361,083)	(373,548)	(12,465)	3.45%
	Amortization of Contributions - Utility					
17	Opening Balance		117,665	117,953	288	0.24%
18	Closing Balance	Sch. 4.1	117,953	123,946	5,993	5.08%
19	**Mid-Year Amortization of Contributions**		117,809	120,950	3,140	2.67%
20	Less: Construction Work in Progress (CWIP) - Mid-Year		(38,350)	(44,132)	(5,782)	15.08%
21	Less: Contributions Work in Progress (KWIP) - Mid-Year		1,162	1,245	84	7.20%
22	**Construction Work in Progress (CWIP) - Mid-Year**		(37,188)	(42,887)	(5,699)	15.32%
23	**Mid-Year Utility Plant in Service**		1,277,333	1,282,009	4,676	0.37%
	Necessary Working Capital					
24	Cash Expenses		2,033	3,276	1,243	61.14%
25	Materials and Supplies		1,776	1,770	(6)	(0.34%)
26	Prepayments and Deferrals		16,500	30,242	13,742	83.28%
27	Financial Items		2,106	4,185	2,079	98.72%
28	Goods and Services Tax (GST)		(43)	234	277	(644.19%)
			22,372	39,707	17,335	77.49%
29	**Mid-Year Rate Base**	Sch. 2	**1,299,705**	**1,321,716**	**22,011**	**1.69%**

ATCO Gas (South)
SUMMARY OF MID-YEAR RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Guidelines:
(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) If there was a negotiated settlement in place for the reporting year please state the approved negotiated settlement numbers in the decision colum
(3) Please note the source of the numbers in the decision or negotiated settlement as applicable.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2018, 2019 and 2020.

Variance Explanations

Cross-Ref	
2	**Expenditures** refer to Schedule 4.2.
3, 9	**Retirements** are lower than prior year mainly due Decision 24188-D02-2020 which approved the use of amortization accounting for a number of accounts including Software and Leasehold Improvements resulting in retirements for balances older than the approved amortization period in 2020.
4	**Adjustments and Transfers** are higher than prior year mainly due to asset transfers between ATCO Pipelines and ATCO Gas associated with the Urban Pipelines Replacement (UPR) Program.
8	**Depreciation Expense** refer to Schedule 4.0.
20	**Construction Work in Progress (CWIP)** is higher than prior year primarily due to IT projects as a result of the continued work on the ATCO Gas CIS Replacement Program.
24	**Cash Expenses** are higher mainly due to income taxes and higher operation and maintenance.
26	**Prepayments and Deferrals** are higher than the prior year mainly due to the outstanding collection resulting from the implementation of approved depreciation parameters as per Decision 24188-D02-2020.
27	**Financial Items** are higher than the prior year mainly due to lower dividends.

ATCO Gas (South)

SUMMARY OF DEGREE DAYS & YEAR END CUSTOMERS AND THROUGHPUT

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Description	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Actual vs. Forecast #	Variance 2021 Actual vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
1	10 Year Average Normal Degree Days	4,031	4,033	4,033	-	0.00%	2	0.05%
	Number of Year-End Customers							
2	Residential	573,046	581,113	576,424	4,689	0.81%	8,067	1.41%
3	Commercial	44,362	44,872	44,630	242	0.54%	510	1.15%
4	Industrial	191	189	191	(2)	(1.05%)	(2)	(1.05%)
5	Irrigation	4	750	7	743	10614.29%	746	18650.00%
6	Total Customers	617,603	626,924	621,252	5,672	0.91%	9,321	1.51%
	Normalized Throughput - TJs							
7	Residential	64,910	63,154	64,434	(1,280)	(1.99%)	(1,756)	(2.71%)
8	Commercial	61,286	60,435	62,375	(1,940)	(3.11%)	(851)	(1.39%)
9	Industrial	8,041	7,921	8,232	(311)	(3.78%)	(120)	(1.49%)
10	Irrigation	182	283	268	15	5.60%	101	55.49%
11	Total Normalized Throughput	134,419	131,793	135,309	(3,516)	(2.60%)	(2,626)	(1.95%)

Note:

The 2020 throughput is normalized based on the ten year average temperatures ending 2018.
The 2021 throughput is normalized based on the ten year average temperatures ending 2019.
The 2021 customers and throughput forecasts are based on AUC Decision 25863-D01-2020.

In Decision 20820-D01-2015, the Commission directed in subsequent PBR annual rate adjustment filings to provide information on the variance from forecast to actual billing determinants in each completed prior year of the PBR term, as well as identify drivers behind a variance larger than ±5 per cent on an annual basis.

Effective April 1, 2021, the irrigation fixed charge rate is only applicable from May 1 to September 30 as per Decision 25428-D01-2020. The irrigation number of year end customers has increased to 750 customers due to seasonal irrigation customers being kept active year-round as per Decision 25428-D01-2020 which became effective in 2021. Prior to 2021, irrigation customers were physically turned off after the irrigation season ended in September. This change in methodology was made after the release of Decision 25863-D01-2020 and therefore it was not incorporated in the 2021 PBR irrigation customer forecast.

ATCO Gas (South)
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Operating & Maintenance Expense					
1	Gas Management		309	302	(6)	(2.04%)
2	Transmission		111,923	132,406	20,483	18.30%
3	Distribution		45,569	52,915	7,345	16.12%
4	General		4,525	4,992	466	10.31%
5	Sales and Transportation Promotion		4,984	1,848	(3,136)	(62.93%)
6	Customer Accounting		7,004	7,684	680	9.71%
7	Administration and General		60,582	54,156	(6,426)	(10.61%)
8	**Total Operating & Maintenance Expense**		234,895	254,302	19,407	8.26%
9	Less: Non-Utility O&M		10,154	7,528	(2,626)	(25.86%)
10	**Operating & Maintenance Expense - Net**	Sch. 10	224,741	246,774	22,033	9.80%

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.
(2) Global reductions refers to the reduction of fees chargeable as deemed in the rate application decision.
(3) Please add line items as needed to more clearly identify major O&M expenses.

Variance Explanations

Cross - Ref	
2	**Transmission** costs are higher than prior year mainly due to an increase in rates.
3	**Distribution** costs are higher than prior year mainly due to increased volumes in operational maintenance and customer services as well as lump sum NGEA bargaining payouts.
5	**Sales and Transportation Promotion** costs are lower than prior year mainly due a decrease in non-utility sales**.**
7	**Administration and General** costs are lower than prior year mainly due to lower IT transition costs associated with the re-alignment of IT services.
9	**Non-Utility O&M** costs are lower than prior year mainly due a decrease in non-utility sales, partially offset by an increase in sponsorships and donations.

ATCO Gas (South)
SUMMARY OF DEPRECIATION
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	Depreciation Expense					
1	Distribution Plant		84,336	87,198	2,862	3.39%
2	General Plant		16,186	16,504	318	1.96%
3	Sub-total	Sch. 4.1	100,522	103,702	3,180	3.16%
4	Less: Capitalized Depreciation		(2,182)	(1,946)	236	(10.82%)
5	Sub-total		98,340	101,756	3,416	3.47%
6	Non-Utility Depreciation	Sch. 4.1	(311)	(343)	(32)	10.28%
7	**Utility Depreciation Expense**	Sch. 2.1	98,029	101,413	3,384	3.45%
8	Amortization of Contributions	Sch. 4.1	(6,756)	(6,954)	(198)	2.93%
9	Non-Utility Amortization of Contributions	Sch. 4.1	22	21	(1)	(3.86%)
10	**Amortization of Contributions - Utility**		(6,734)	(6,933)	(199)	2.95%
	Other					
11	Production Abandonments		700	700	-	0.00%
12	**Total Utility Depreciation Expenses**	Sch. 10	**91,995**	**95,180**	**3,185**	**3.46%**

Guidelines:

(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.

Other Information

2020 amounts above reflect the implementation of approved depreciation parameters as per Decision 24188-D02-2020 for 2020 only.

Variance Explanations

Cross-Ref	
1	Distribution Plant is higher than the prior year due to a higher opening depreciable base as well as an increase in depreciation resulting from 2021 capital additions.

SCHEDULE 4.1

ATCO Gas (South)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Transfers	2021 Adjustments	Balance at 12/31/2021
	Distribution							
1	Land		4,076	272	-	-	-	4,348
2	Land Rights		7,337	3,139	-	-	-	10,476
3	Structures & Improvements		27,132	2,620	35	-	(30)	29,687
4	Services & Alterations		660,916	23,064	1,572	-	(398)	682,009
5	Regulators & Meters		222,693	7,329	531	-	1,934	231,424
6	Mains		1,087,305	40,436	1,380	6	(0)	1,126,366
7	Measurement & Regulating Equipment		115,008	10,764	1,133	1	(1,904)	122,737
8	Meters		121,060	11,316	4,012	-	-	128,364
9	Renewable Energy		2,908	-	-	-	-	2,908
10	Distribution		2,248,433	98,940	8,662	7	(398)	2,338,319
	General Plant & Equipment							
11	Franchises		680	23	49	-		654
12	Land		10,034	-	-	-		10,034
13	Structures & Improvements		63,725	1,466	0	-		65,191
14	General Plant & Equipment		74,439	1,489	49	-	-	75,879
	Moveable Equipment							
15	Office Furniture & Equipment		7,765	157	249	-	(16)	7,658
16	Transportation Equipment		43,608	3,245	2,724	-	-	44,129
17	Heavy Work Equipment		11,509	1,055	296	-	-	12,268
18	Tools & Work Equipment		11,755	1,190	539	-	397	12,802
19	Cogeneration Equipment		1,104	-	-	-	-	1,104
20	Communication Equipment		17,323	419	519	-	(150)	17,073
21	Stores, Shop Equipment & Lab Equipment		7,568	167	373	-	-	7,362
22	Leasehold Improvements		3,558	39	797	-	-	2,800
23	Electronic Data Processing Equipment		4,233	2,969	189	-	166	7,179
24	Base Maps		536	-	38	-	-	498
25	Software Development		48,641	12,151	7,660	-	-	53,133
26	Moveable Equipment		157,600	21,391	13,383	-	398	166,006
27	Capital Work in Progress (CWIP) - Utility		35,835	16,595				52,430
28	Capital Work in Progress (CWIP) - Non Utility		967	(64)				903
29	**Capital Work in Progress (CWIP)**		36,801	16,531	-	-	-	53,332
30	Total Capital Assets	Sch. 2.1 / 4.2	**2,517,273**	**138,351**	**22,095**	**7**	**(0)**	**2,633,536**
31	Non-Utility Assets		8,963	-	713			**8,250**
32	**Total Utility Capital Assets**		**2,508,310**	**138,351**	**21,382**	**7**	**(0)**	**2,625,287**
	Contributions							
33	Utility		363,730	18,085	939	-		380,876
34	Non-Utility		757	-	-	-		757
35	Contributions Work in Progress (KWIP) - Utility		2,197	(1,904)	-	-		293
36	Contributions Work in Progress (KWIP) - Non Utility							-
36	Total Contributions	Sch 2.1	**366,684**	**16,181**	**939**	**-**	**-**	**381,926**

ATCO Gas (South)
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	Depreciation Provision	2021 Retirements	2021 Removals	2021 Salvage	2021 Adjustments	Balance at 12/31/2021
	Distribution								
1	Land		-	-	-	-	-	-	-
2	Land Rights		361	114	-	-	-	-	475
3	Structures & Improvements		6,412	898	35	214	(0)	(4)	7,057
4	Services & Alterations		311,056	32,015	1,572	5,017	-	(38)	336,443
5	Regulators & Meters		88,789	9,531	531	4	-	210	97,995
6	Mains		368,085	31,364	1,380	2,247	12	6	395,840
7	Measurement & Regulating Equipment		38,383	4,153	1,133	595	(0)	(205)	40,603
8	Meters		40,896	8,995	4,012	-	817	-	46,697
9	Renewable Energy		1,005	127	-	-	-	-	1,133
10	**Distribution**		854,986	87,198	8,662	8,077	829	(32)	926,242
	General Plant & Equipment								
11	Franchises		556	68	49	-	-	-	575
12	Land		-	-	-	-	-	-	-
13	Structures & Improvements		29,081	2,090	0	152	-	-	31,019
14	**General Plant & Equipment**		29,636	2,158	49	152	-	-	31,594
	Moveable Equipment								
15	Office Furniture & Equipment		3,813	437	249	-	-	(3)	3,998
16	Transportation Equipment		21,002	2,768	2,724	12	445	-	21,478
17	Heavy Work Equipment		5,475	549	296	0	40	-	5,768
18	Tools & Work Equipment		4,262	1,215	539	-	9	38	4,985
19	Cogeneration Equipment		1,123	9	-	-	-	-	1,132
20	Communication Equipment		11,190	727	519	21	-	(6)	11,372
21	Stores, Shop & Lab Equipment		4,230	570	373	1	-	-	4,427
22	Electronic Data Processing Equipment		1,832	1,149	189	-	-	9	2,801
23	Base Maps		547	(10)	38	-	-	-	499
24	Leaseholds & Improvements		1,244	457	797	3	-	-	901
25	Software Development		17,044	6,474	7,660	-	-	-	15,858
26	Moveable Equipment		71,763	14,345	13,383	37	494	38	73,220
27	Retirements Work in Progress (RWIP)		(1,389)			38			(1,427)
28	Total Accumulated Depreciation	Sch. 2.1 / 4	**954,996**	**103,702**	**22,095**	**8,304**	**1,324**	**6**	**1,029,629**
29	**Non-Utility Assets**		**3,194**	343	713				**2,823**
30	Total Utility Accumulated Depreciation		**951,803**	**103,359**	**21,382**	**8,304**	**1,324**	**6**	**1,026,806**
	Contributions								
31	Utility		117,953	6,933	939	-	-	-	123,946
32	Non-Utility	Sch. 4	396	21	-	-	-	-	417
33	Total Contributions	Sch 2.1 / 4	**118,349**	**6,954**	**939**	**-**	**-**	**-**	**124,363**
34	Net Property, Plant, and Equipment		**1,313,942**						**1,346,345**
35	Net Property, Plant and Equipment (Non-Utility)		**(5,408)**						**(5,087)**
36	Net Property, Plant, and Equipment (Utility)		**1,308,534**						**1,341,258**
	Less CWIP & KWIP (Utility)		(33,638)						(52,136)
	Utility Plant in Service		**1,274,896**						**1,289,122**
	Mid Year Utility Plant in Service								**1,282,009**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Provide a detailed breakdown of items included in "Other", in a supporting sub-schedule.
(3) Year-end balances for each category must be reconciled on Schedule 11 to the audited Balance Sheet.

ATCO Gas (South)
SUMMARY OF CAPITAL EXPENDITURES
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross- Reference	2020 Year End	2021 Year End	Variance 2021 vs. 2020	
	Distribution					
1	Extensions		15,401	15,883	481	3.13%
2	Services		14,069	14,951	882	6.27%
3	Meters, Regulators and Installations		19,491	20,235	744	3.82%
4	Improvements and MRRP		37,718	49,131	11,413	30.26%
5	Sub-Total		86,679	100,199	13,520	15.60%
	Land and Structures					
6	General		907	2,250	1,343	148.06%
	Moveable Equipment					
7	General		6,043	7,131	1,088	18.01%
8	Communication and Lab Equipment		616	356	(260)	(42.23%)
9	Software Development		15,026	28,414	13,388	89.10%
10	Sub-Total		21,685	35,902	13,128	60.54%
11	**Capital Expenditures**	Sch. 2.1 / 4.1	**109,272**	**138,351**	**29,080**	**26.61%**
12	**Capital Expenditures - Non-Utility**		-	-	0	N/A
13	**Capital Expenditures - Utility**		**109,272**	**138,351**	**29,080**	**26.61%**

Guidelines:

(1) Asset categories need to be identified by the individual utilities. However, they should show sufficient breakdown to allow for reasonable understanding of operations.
(2) Please add line items as needed to give sufficient understanding of the main capital additions in the reporting year.

Variance Explanations

Cross-Ref	
4	**Improvements and MRRP** expenditures were higher than prior year in steel and plastic mains replacement and Transmission Driven work. This was a ramp up of construction due to the shorter construction season in 2020 due to the pandemic as the replacement programs involve extensive work inside customers homes.
6	**Land and Structures General** expenditures were higher than prior year mainly due to installation of energy saving smart equipment.
7	**Moveable Equipment General** expenditures were higher than prior year due mainly to the purchase of new fleet vehicles.
9	**Software Development** higher ATCO Gas CIS Replacement Program costs due to increased project activities in 2021 compared to 2020.

ATCO Gas (South)
SUMMARY OF UTILITY REVENUE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Act vs. Forecast #	Variance 2021 Act vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	REVENUE CLASSIFICATIONS								
	Residential								
1	Average Number of Customers		569,746	576,850	573,205	3,645	0.64%	7,104	1.25%
2	Revenue		279,346	303,038	303,078	(40)	(0.01%)	23,692	8.48%
	Commercial (Apartment)								
3	Average Number of Customers		3,569	3,581	3,583	(2)	(0.06%)	12	0.34%
4	Revenue		12,563	14,014	14,138	(124)	(0.88%)	1,451	11.55%
	Commercial (Non-Apartment)								
5	Average Number of Customers		40,484	40,928	40,733	195	0.48%	444	1.10%
6	Revenue		88,315	98,294	99,827	(1,533)	(1.54%)	9,979	11.30%
	Industrial								
7	Average Number of Customers		191	190	191	(1)	(0.52%)	(1)	(0.52%)
8	Revenue		6,918	7,451	7,490	(39)	(0.52%)	533	7.70%
	Irrigation								
9	Average Number of Customers		384	505	398	107	26.88%	121	31.51%
10	Revenue		330	454	433	21	4.85%	124	37.58%
11	Total Average Number of Customers		614,374	622,054	618,110	3,944	0.64%	7,680	1.25%
12	Sub-Total Rate Revenue		387,472	423,251	424,966	(1,715)	(0.40%)	35,779	9.23%
	RATE ACCRUALS REVENUE								
13	Rate Accruals Revenue		16,510	8,681				(7,829)	(47.42%)
	FRANCHISE REVENUE								
14	Franchise Fee Revenue		77,370	90,135				12,765	16.50%
	OTHER REVENUE								
15	Other Revenue (Please See Below)		8,888	8,602				(285)	(3.21%)
16	**TOTAL UTILITY REVENUE**	Sch 10	**490,240**	**530,669**				**40,430**	8.25%

SCHEDULE 6

ATCO Gas (South)
SUMMARY OF UTILITY REVENUE
FOR THE YEAR ENDED DECEMBER 31, 2021
($000s)

Line No.	Description	Cross-Ref.	2020 Actual	2021 Actual	2021 Forecast	Variance 2021 Act vs. Forecast #	Variance 2021 Act vs. Forecast %	Variance 2021 vs. 2020 #	Variance 2021 vs. 2020 %
	OTHER REVENUE								
17	ATCO Pipelines		6,104	5,885				(219)	(3.58%)
18	Other Affiliates		488	763				275	56.29%
19	Facility Repairs		710	703				(7)	(0.94%)
20	Reinstatement Fees		406	1,105				699	172.16%
21	Miscellaneous		1,180	146				(1,033)	(87.60%)
22	Total Other Revenue		8,888	8,602				(285)	(3.21%)

Guidelines:
(1) Variance explanations required for $2 million, or 10% or greater and any difference equal to or greater than $500K.

Note: The 2021 rate revenue forecast is based on the 2021 delivery rates applied to the PBR approved billing determinant forecast.

Revenue Variance Explanations

Cross-Ref	
2	**Residential Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
4	**Commercial (Apartment) Revenue** is higher than prior year primarily due to higher delivery rates in 2021.
6	**Commercial (Non-Apartment) Revenue** is higher than prior year primarily due to higher delivery rates and number of customers in 2021.
14	**Franchise Revenue** is higher than prior year primarily due to higher delivery rates, cost of gas and number of customers in 2021.
20	**Reinstatement Fees Revenue** is higher than prior year primarily due to a higher number of disconnects/reconnects in 2021.
21	**Other Miscellaneous Revenue** is lower than prior year primarily due to lower secondary services.

ATCO Gas (South)
UTILITY INCOME
FOR THE YEAR ENDED DECEMBER 31, 2021
INCOME STATEMENT ITEMS
($000s)

Line No.	Description	Cross-Reference	2021 Utility Total	2020 Utility Total	Variance 2021 vs. 2020	
	Revenues					
1	Total Operating Revenue		530,669	490,240	40,430	8.25%
2		Sch. 6	530,669	490,240	40,430	8.25%
	Operating Expenses					
3	Operation and Maintenance (including property tax)		246,974	224,937	22,037	9.80%
4	Depreciation and Amortization	Sch. 4	95,180	91,995	3,185	3.46%
5	Franchise Fees	Sch. 6	90,135	77,370	12,765	16.50%
6			432,289	394,303	37,987	29.76%
7	**Income Tax**		9,160	11,428	(2,268)	(19.85%)
8	**Return**	Sch. 2	**89,220**	**84,509**	**4,711**	**5.57%**

(a division of ATCO Gas and Pipelines Ltd.)

ATCO GAS

FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021

Independent auditor's report

To the Shareowner of ATCO Gas and Pipelines Ltd.

Our opinion

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of ATCO Gas, a division of ATCO Gas and Pipelines Ltd., (the Division) as at December 31, 2021 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited
The Division's financial statements comprise:

- the statement of earnings for the year ended December 31, 2021;
- the statement of comprehensive income for the year ended December 31, 2021;
- the balance sheet as at December 31, 2021;
- the statement of changes in equity for the year ended December 31, 2021;
- the statement of cash flow for the year ended December 31, 2021; and
- the notes to the financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Division in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Division's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Division or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Division's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Division's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Division’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Division to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
April 29, 2022

TABLE OF CONTENTS

STATEMENT OF EARNINGS

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2021**	**2020**
Revenues	4	**1,147,670**	1,079,975
Costs and expenses			
Salaries, wages and benefits		**(99,606)**	(90,870)
Energy transmission and transportation		**(265,821)**	(224,640)
Plant and equipment maintenance		**(64,120)**	(50,555)
Depreciation and amortization	9, 10	**(144,180)**	(136,459)
Franchise fees		**(225,390)**	(207,263)
Property and other taxes		**(626)**	(593)
Other	5	**(118,510)**	(129,247)
Operating profit		**229,417**	240,348
Interest income		**312**	616
Interest expense	6	**(77,190)**	(78,553)
Net finance costs		**(76,878)**	(77,937)
Earnings before income taxes		**152,539**	162,411
Income taxes	7	**(36,741)**	(38,524)
Earnings for the year		**115,798**	123,887

See accompanying Notes to Financial Statements.

STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2021**	**2020**
Earnings for the year		**115,798**	123,887
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits [(1)]	12	**8,121**	(5,418)
Comprehensive income for the year		**123,919**	118,469

(1) Net of income taxes of $(2.4) million for the year ended December 31, 2021 (2020 - $1.6 million).

See accompanying Notes to Financial Statements.

BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2021	2020
ASSETS			
Current assets			
Accounts receivable and contract assets	13	**274,610**	203,728
Accounts receivable from parent and affiliate companies	13, 23	**5,069**	4,944
Inventories	8	**1,364**	2,108
Prepaid expenses and other current assets		**3,535**	4,713
		284,578	215,493
Non-current assets			
Property, plant and equipment	9	**3,960,655**	3,843,164
Intangibles	10	**170,771**	130,559
Right-of-use assets		**2,432**	3,609
Other assets		**10,866**	12,029
Total assets		**4,429,302**	4,204,854
LIABILITIES			
Current liabilities			
Bank indebtedness		**403**	2,074
Short-term advances from parent company	13, 23	**121,800**	20,000
Accounts payable and accrued liabilities		**215,989**	209,473
Accounts payable to parent and affiliate companies	23	**34,660**	20,028
Long-term debt	11,23	**26,803**	20,000
Provisions and other current liabilities	3	**37,542**	34,295
		437,197	305,870
Non-current liabilities			
Deferred income tax liabilities	7	**308,379**	283,249
Retirement benefit obligations	12	**78,289**	88,363
Customer contributions	13	**566,377**	546,285
Other liabilities		**1,481**	2,387
Long-term debt	11, 23	**1,744,786**	1,691,777
Total liabilities		**3,136,509**	2,917,931
EQUITY			
Equity preferred shares	14, 23	**64,273**	88,318
Class A and Class B share owner's equity			
Class A and Class B shares	15	**119,107**	119,107
Retained earnings		**1,109,413**	1,079,498
		1,228,520	1,198,605
Total equity		**1,292,793**	1,286,923
Total liabilities and equity		**4,429,302**	4,204,854

See accompanying Notes to Financial Statements.

DIRECTOR

DIRECTOR

STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
December 31, 2019		119,107	88,318	1,077,806	–	1,285,231
Earnings for the year		–	–	123,887	–	123,887
Other comprehensive loss		–	–	–	(5,418)	(5,418)
Loss on retirement benefits transferred to retained earnings	12	–	–	(5,418)	5,418	–
Dividends	14, 15	–	–	(116,777)	–	(116,777)
December 31, 2020		119,107	88,318	1,079,498	–	1,286,923
Earnings for the year		–	–	**115,798**	–	**115,798**
Other comprehensive income		–	–	–	**8,121**	**8,121**
Gain on retirement benefits transferred to retained earnings	12	–	–	**8,121**	**(8,121)**	–
Redemption of equity preferred shares to parent company	14	–	**(24,045)**	**(15)**	–	**(24,060)**
Dividends	14, 15	–	–	**(93,989)**	–	**(93,989)**
December 31, 2021		**119,107**	**64,273**	**1,109,413**	–	**1,292,793**

See accompanying Notes to Financial Statements.

STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Operating activities			
Earnings for the year		**115,798**	123,887
Adjustments to reconcile earnings to cash flows from operating activities	16	**254,509**	283,817
Changes in non-cash working capital	16	**(47,026)**	(10,401)
Cash flows from operating activities		**323,281**	397,303
Investing activities			
Additions to property, plant and equipment		**(237,788)**	(205,582)
Proceeds on disposal of property, plant and equipment		**–**	4
Additions to intangibles		**(53,223)**	(28,041)
Changes in non-cash working capital	16	**8,924**	10,213
Other		**(5,620)**	2,359
Cash flows used in investing activities		**(287,707)**	(221,047)
Financing activities			
Issue of long-term debt	11	**80,000**	40,000
Repayment of long-term debt	11	**(20,000)**	(23,738)
Redemption of equity preferred shares	14	**(24,060)**	–
Dividends paid on equity preferred shares	14	**(2,989)**	(3,377)
Dividends paid to Class A and Class B share owner	15	**(91,000)**	(113,400)
Interest paid		**(75,394)**	(77,182)
Other		**(2,260)**	(1,928)
Cash flows used in financing activities		**(135,703)**	(179,625)
Decrease in cash position		**(100,129)**	(3,369)
Beginning of year		**(22,074)**	(18,705)
End of year	16	**(122,203)**	(22,074)

See accompanying Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2021

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE DIVISION AND ITS OPERATIONS

ATCO Gas ("ATCO Gas") and ATCO Pipelines are divisions of ATCO Gas and Pipelines Ltd. (AGPL). Each division is operated by a separate management group, and each maintains its own books of account. ATCO Gas is engaged in the distribution of natural gas in the Province of Alberta and the Lloydminster area of Saskatchewan. Its registered office and head office is at 4th floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4. AGPL is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these financial statements, ATCO Gas is also referred to as "the Company".

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Management authorized these financial statements for issue on April 29, 2022.

BASIS OF MEASUREMENT

The financial statements are prepared on a historic cost basis, except for retirement benefit obligations which are carried at remeasured amounts. ATCO Gas' significant accounting policies are described in Note 24.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The financial statements are presented in Canadian dollars, which is ATCO Gas' functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, assumptions and estimates are described in Note 20.

ADOPTION OF NEW ACCOUNTING INTERPRETATION

In April 2021, the IFRS Interpretations Committee (IFRIC) published a final agenda decision with respect to recognition of certain configuration and customization expenditures related to cloud computing with retrospective application. Costs that do not meet the capitalization criteria should be expensed as incurred. Any changes resulting from the decision were required to be implemented by December 31, 2021.

As a result of the review of the impact of the decision on the financial statements, ATCO Gas recorded a decrease to intangible assets of $2.5 million with a corresponding increase to other expenses in the statement of earnings (Note 10).

3. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of the Company,
- one-time gains and losses,
- impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of earnings used by the Chief Operating Decision Maker (CODM) to assess performance and allocate resources. Other accounts in the financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

	2021	2020
Adjusted earnings	**142,397**	145,613
Early termination of the master service agreement for managed IT services	**(15,647)**	(24,987)
Restructuring costs	**(486)**	(3,629)
Rate-regulated activities	**(8,655)**	9,717
IT Common Matters decision	**(4,800)**	(6,204)
Dividends on equity preferred shares	**2,989**	3,377
Earnings for the year	**115,798**	123,887

Early termination of the master service agreement for managed IT services

On December 31, 2020, Canadian Utilities Limited, signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) (subsequently novated to Kyndryl Canada Ltd.) to provide managed information technology (IT) services. These services were previously provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring in December 2024. The transition of the managed IT services from Wipro to IBM commenced on February 1, 2021 and was completed at December 31, 2021.

On December 31, 2020, ATCO Gas recognized an onerous contract provision of $32.5 million ($25.0 million after-tax), which represents management's best estimate of the costs to exit the Wipro MSA. The provision is included in provisions and other current liabilities in the balance sheet and other expenses in the statement of earnings. The onerous contract provision is not in the normal course of business and has been excluded from Adjusted Earnings.

In addition, the Company recognized transition costs of $20.3 million ($15.6 million after-tax) in 2021. The transition costs related to activities to transfer the managed IT services from Wipro to IBM. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

Restructuring costs

In 2021, ATCO Gas recorded restructuring and other costs of $0.5 million, after-tax, that were not in the normal course of business. These costs mainly related to staff reductions and associated severance costs.

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that ATCO Gas is eligible to adopt. In the absence of this guidance, ATCO Gas does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, ATCO Gas recognizes revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

ATCO Gas uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles (GAAP) to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of ATCO Gas' rate-regulated activities. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs and impact of weather changes on revenue.	ATCO Gas defers the recognition of cash received in advance of future expenditures.	ATCO Gas recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes and the impact of weather changes on revenue.	ATCO Gas recognizes revenues associated with recoverable costs in advance of future billings to customers.	ATCO Gas records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods. See regulatory decisions below.	ATCO Gas recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	ATCO Gas does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	ATCO Gas recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	ATCO Gas recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

The significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2021	2020
Additional revenues billed in current period		
Future removal and site restoration costs [(1)]	**65,497**	45,609
Impact of weather changes on revenue [(2)]	**(820)**	1,763
Revenues to be billed in future periods		
Deferred income taxes [(3)]	**(30,983)**	(25,363)
Distribution rate relief [(4)]	**(70,873)**	–
Settlement of regulatory decisions and other items [(5)]	**28,524**	(12,292)
	(8,655)	9,717

(1) *Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.*

(2) *ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.*

(3) *Income taxes are billed to customers when paid by ATCO Gas.*

(4) *In 2021, in response to the ongoing COVID-19 Pandemic, ATCO Gas applied for interim rate relief for customers to hold prior year distribution base rates in place. Following approval by the AUC, ATCO Gas realized a decrease in earnings of $70.9 million. This will be recovered from customers in 2022.*

(5) *In 2021, ATCO Gas collected $53 million related to depreciation and transmission rate riders, which was partly offset by a decrease in earnings of $28 million related to payments of transmission costs.*

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by CU Inc.'s parent, Canadian Utilities Limited, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2021 was $4.8 million (2020 - $6.2 million).

4. REVENUES

The Company disaggregates revenues based on the revenue streams. The disaggregation of revenues by revenue streams for the year ended December 31 are shown below:

	2021	2020
Distribution services [(1)]	**876,834**	817,580
Customer contributions (*Note 13*)	**16,823**	16,904
Franchise fees	**224,699**	208,384
Other	**29,314**	37,107
	1,147,670	1,079,975

(1) *For the year ended December 31, 2021, revenues from distribution services include $82.2 million of unbilled revenues (2020 - $52.9 million). At December 31, 2021, $82.2 million of the unbilled trade accounts receivables are included in accounts receivable and contract assets (2020 - $52.9 million).*

5. OTHER COSTS AND EXPENSES

In addition to rent, utilities, and goods and services such as professional fees, contractor costs, technology related expenses, advertising and other general and administrative expenses, other costs and expenses included costs related to the transition of managed information technology services of $20.3 million ($15.6 million after-tax) in 2021 (2020 - $32.5 million) (see Note 3).

6. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2021	2020
Long-term debt	**75,870**	76,910
Credit facility and standby charges	**1,367**	1,059
Retirement benefits net interest expense	**1,296**	1,434
Amortization of deferred financing charges	**559**	486
Other	**1,469**	1,686
	80,561	81,575
Less: interest capitalized *(Note 9, 10)*	**(3,371)**	(3,022)
	77,190	78,553

Borrowing costs capitalized to property, plant and equipment during 2021 were calculated by applying a weighted average interest rate of 4.44 per cent to expenditures on qualifying assets (2020 - 4.56 per cent).

7. INCOME TAXES

INCOME TAX EXPENSE

ATCO Gas does not file an income tax return. Its divisional share of the income tax provision is calculated as if it was a legal entity.

The income tax rate for 2021 is 23.0 per cent (2020 - 24.0 per cent).

The components of income tax expense are summarized below.

	2021	2020
Current income tax expense		
Expense for the year	**16,806**	40,943
Adjustment in respect of prior years	**(2,768)**	(751)
	14,038	40,192
Deferred income tax expense		
Reversal of temporary differences	**18,602**	(2,874)
Adjustment in respect of prior years	**4,101**	1,206
	22,703	(1,668)
	36,741	38,524

The reconciliation of statutory and effective income tax expense is as follows:

	2021		2020	
Earnings before income taxes	**152,539**	**%**	162,411	%
Income taxes, at statutory rates	**35,084**	**23.0**	38,979	24.0
Part VI.I tax net of transfer benefit	**233**	**0.2**	216	0.1
Other	**1,424**	**0.9**	(671)	(0.4)
	36,741	**24.1 %**	38,524	23.7 %

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Retirement Benefit Obligations	Other	Total
December 31, 2019	269,015	28,107	(18,327)	7,726	286,521
Charge (credit) to earnings	15,067	4,404	(335)	(20,803)	(1,667)
Credit to other comprehensive income	–	–	(1,622)	–	(1,622)
Other	–	–	–	17	17
December 31, 2020	284,082	32,511	(20,284)	(13,060)	283,249
Charge (credit) to earnings	**22,180**	**9,018**	**(90)**	**(8,406)**	**22,702**
Charge to other comprehensive income	–	–	**2,426**	–	**2,426**
Other	–	–	–	**2**	**2**
December 31, 2021	**306,262**	**41,529**	**(17,948)**	**(21,464)**	**308,379**

ATCO Gas does not expect its deferred income tax liabilities to reverse within the next twelve months.

8. INVENTORIES

Inventories at December 31 are comprised of:

	2021	2020
Raw materials and consumables	**1,364**	2,108

For the year ended December 31, 2021, inventories recognized as an expense were $1.1 million (2020 - $1.0 million).

9. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Distribution Plant	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2019	4,884,342	185,265	70,860	28,543	5,169,010
Additions	–	–	211,574	–	211,574
Transfers	224,846	3,090	(228,319)	383	–
Retirements and disposals	(36,955)	(11,869)	–	(655)	(49,479)
December 31, 2020	5,072,233	176,486	54,115	28,271	5,331,105
Additions	–	–	**245,686**	–	**245,686**
Transfers	**229,755**	**5,823**	**(235,995)**	**417**	–
Retirements and disposals	**(24,284)**	**(938)**	–	**(324)**	**(25,546)**
December 31, 2021	**5,277,704**	**181,371**	**63,806**	**28,364**	**5,551,245**
Accumulated depreciation					
December 31, 2019	1,323,486	74,089	–	16,182	1,413,757
Depreciation	117,903	2,603	–	1,121	121,627
Retirements and disposals	(34,924)	(11,865)	–	(654)	(47,443)
December 31, 2020	1,406,465	64,827	–	16,649	1,487,941
Depreciation	**128,290**	**4,662**	–	**966**	**133,918**
Retirements and disposals	**(30,007)**	**(938)**	–	**(324)**	**(31,269)**
December 31, 2021	**1,504,748**	**68,551**	–	**17,291**	**1,590,590**
Net book value					
December 31, 2020	3,665,768	111,659	54,115	11,622	3,843,164
December 31, 2021	**3,772,956**	**112,820**	**63,806**	**11,073**	**3,960,655**

The additions to property, plant and equipment included $1.6 million of interest capitalized during construction for the year ended December 31, 2021 (2020 - $2.0 million).

10. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Work-in-Progress	Other	Total
Cost					
December 31, 2019	223,944	33,793	34,353	1,256	293,346
Additions	–	–	28,041	–	28,041
Transfers	22,319	3,158	(25,477)	–	–
Retirements	(151,547)	(31)	–	–	(151,578)
December 31, 2020	94,716	36,920	36,917	1,256	169,809
Additions	**–**	**–**	**53,201**	**–**	**53,201**
Transfers	**23,832**	**5,543**	**(29,398)**	**23**	**–**
Retirements	**(15,304)**	**80**	**–**	**(414)**	**(15,638)**
December 31, 2021	**103,244**	**42,543**	**60,720**	**865**	**207,372**
Accumulated amortization					
December 31, 2019	167,891	3,941	–	969	172,801
Amortization	17,192	681	–	125	17,998
Retirements	(151,548)	(1)	–	–	(151,549)
December 31, 2020	33,535	4,621	–	1,094	39,250
Amortization	**12,440**	**518**	**–**	**106**	**13,064**
Retirements	**(15,304)**	**5**	**–**	**(414)**	**(15,713)**
December 31, 2021	**30,671**	**5,144**	**–**	**786**	**36,601**
Net book value					
December 31, 2020	61,181	32,299	36,917	162	130,559
December 31, 2021	**72,573**	**37,399**	**60,720**	**79**	**170,771**

The additions to intangibles included $1.8 million of interest capitalized during construction for year ended December 31, 2021 (2020 - $1.0 million).

In 2021, ATCO Gas recorded a decrease to intangibles of $2.5 million with a corresponding increase to other expenses in the statement of earnings as a result of the review of the impacts of IFRIC on recognition of certain configuration and customization expenditures related to cloud computing costs (Note 2).

11. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2021	2020
Debentures - unsecured	4.345% (2020 - 4.404%)	**1,781,432**	1,721,432
(interest is the average effective interest rate weighted by principal amounts outstanding)			
Less: deferred financing charges		**(9,843)**	(9,655)
		1,771,589	1,711,777
Less: amounts due within one year		**(26,803)**	(20,000)
		1,744,786	1,691,777

Debenture issuances and repayments

In 2021, ATCO Gas issued $80.0 million of 3.174 per cent debentures maturing on September 5, 2051. In 2021, ATCO Gas also repaid $20.0 million of 4.801 per cent debentures.

In 2020, ATCO Gas issued $40.0 million of 2.609 per cent debentures maturing on September 28, 2050. In 2020, ATCO Gas also repaid $23.7 million of 11.770 per cent debentures.

12. RETIREMENT BENEFITS

ATCO Gas, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-registered non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2021.

THE COMPANY'S BENEFIT PLANS

Information about ATCO Gas' participation in the group benefit plans is as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**6,098**	**2,342**	7,918	2,400
Defined contribution plans cost	**7,210**	**–**	7,224	–
Total cost	**13,308**	**2,342**	15,142	2,400
Less: capitalized	**5,855**	**1,171**	7,571	1,200
Net cost recognized	**7,453**	**1,171**	7,571	1,200
Accrued benefit obligations				
Beginning of year	28,009	60,354	25,103	54,832
Defined benefit plan cost	**6,098**	**2,342**	7,918	2,400
Benefit payments	**(1,735)**	**(1,733)**	(1,724)	(1,993)
Contributions to defined benefit plans	**(4,500)**	**–**	(5,212)	–
Actuarial (gains) losses	**(4,104)**	**(6,442)**	1,924	5,115
End of year	**23,768**	**54,521**	28,009	60,354

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Average compensation increase for the year	**2.25 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.16 %**	**3.16 %**	2.58 %	2.58 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.05 %**	n/a	5.11 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) ATCO Gas uses a graded drug cost trend rate, which assumes a 5.05 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2020 was completed in 2021 for the registered defined benefit pension plans. The estimated contribution for 2022 is $4.5 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2023.

13. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2021	2020
Trade accounts receivable and contract assets	**274,314**	203,344
Other accounts receivable	**296**	384
	274,610	203,728

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2021	2020
Trade accounts receivable from parent and affiliate companies	**5,069**	4,944

The significant changes in trade accounts receivable and contract assets are as follows:

December 31, 2019	173,191
Revenue from satisfied performance obligations	1,044,218
Payments received	(1,014,065)
December 31, 2020	203,344
Revenue from satisfied performance obligations	**1,111,449**
Other items not included in revenue	**347**
Payments received	**(1,040,826)**
December 31, 2021	**274,314**

CUSTOMER CONTRIBUTIONS

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of natural gas, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Changes in customer contributions balance are summarized below.

	2021	2020
Beginning of year	546,285	531,391
Receipt of customer contributions	**36,915**	23,546
Amortization	**(16,823)**	(16,904)
Transfers from other liabilities	**–**	8,252
End of year	**566,377**	546,285

14. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

	2021		2020	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**1,360,000**	**34,000**	1,360,000	34,000
2.292% Series 4 (1)	**1,260,000**	**31,500**	1,260,000	31,500
Issuance costs		**(1,227)**		(1,227)
		64,273		64,273

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.243 per cent.

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.14325	1.36 %	June 1, 2026 (4)	Series 5 (5)

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by ATCO Gas or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

	2021		2020	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	–	–	962,422	24,060
Issuance Costs		–		(15)
		–		24,045

In 2021, ATCO Gas redeemed all of the issued 4.60 per cent Series V Preferred Shares for $24.1 million plus accrued dividends.

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of ATCO Gas at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2021	2020
Cumulative Redeemable Preferred Shares		
4.60% Series 1	**1.1500**	1.1500
2.292% Series 4 (1)	**0.5669**	0.5608
Perpetual Cumulative Second Preferred Shares		
4.60% Series V (2)	**0.8625**	1.1500

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.24 per cent.

(2) The 4.60% Series V Preferred Shares were redeemed on August 27, 2021.

The payment of dividends is at the discretion of the Board and depends on the financial condition of ATCO Gas and other factors.

On January 20, 2022, ATCO Gas declared first quarter eligible dividends of $0.28750 per Series 1 Preferred Share and $0.14325 per Series 4 Preferred Share.

15. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2021 and 2020	**2,882,633**	**74,067**	**1,745,518**	**45,040**	**4,628,151**	**119,107**

Class A and B shares have no par value.

ATCO Gas declared and paid cash dividends of $19.66 per Class A non-voting share and Class B common share during 2021 (2020 - $24.5). The payment and amount of dividends is at the discretion of the Board and depends on the financial condition of ATCO Gas and other factors.

On February 18, 2022, ATCO Gas declared a first quarter dividend of $7.1735 per Class A and Class B share.

16. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	2021	2020
Depreciation and amortization	**144,180**	136,459
Income taxes	**36,741**	38,524
Contributions by customers for extensions to plant	**36,915**	23,546
Amortization of customer contributions	**(16,823)**	(16,904)
Net finance costs	**76,878**	77,937
Income taxes (paid) recovered	**(21,105)**	2,800
Interest received	**428**	617
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**–**	32,453
Other	**(2,705)**	(11,615)
	254,509	283,817

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2021	2020
Operating activities		
Accounts receivable and contract assets	**(71,723)**	(29,758)
Accounts receivable from parent and affiliate companies	**(128)**	(1,810)
Inventories	**743**	(3)
Prepaid expenses and other current assets	**1,178**	(1,336)
Accounts payable and accrued liabilities	**33,165**	49,592
Accounts payable to parent and affiliate companies	**(9,017)**	(27,565)
Provisions and other current liabilities	**(1,244)**	479
	(47,026)	(10,401)
Investing activities		
Accounts receivable and contract assets	**841**	298
Accounts payable and accrued liabilities	**8,083**	9,915
	8,924	10,213

CASH POSITION

Cash position in the statement of cash flow at December 31 is comprised of:

	2021	2020
Bank indebtedness	**(403)**	(2,074)
Short-term advances from parent company (*Note 23*)	**(121,800)**	(20,000)
	(122,203)	(22,074)

17. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent company, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on ATCO Gas' current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company’s financial instruments measured at amortized cost at December 31 are as follows:

		2021		2020	
Recurring Measurements	**Note**	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial Liabilities					
Long-term debt	11	**1,771,589**	**2,049,805**	1,711,777	2,179,533

18. RISK MANAGEMENT

ATCO Gas is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. ATCO Gas’ Board is responsible for understanding the principal risks of ATCO Gas’ business, achieving a proper balance between risks incurred and the potential return to share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of ATCO Gas. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect ATCO Gas’ ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparties inability to discharge their contractual obligations to ATCO Gas. ATCO Gas is exposed to credit risk on accounts receivable and contract assets and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the balance sheet.

The majority of ATCO Gas' accounts receivable credit risk is reduced by financial security provided by Direct Energy and by retailers in accordance with provisions contained with Natural Gas Billing Regulation A.R. 185/2003, and ATCO Gas' ability under the Regulation to request recovery through customers rates any losses from retailers beyond that covered by the retailer security provided. At December 31, 2021, ATCO Gas held $135.5 million in letters of credit for certain counterparty receivables (2020 - $107.1 million).

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. The provision for impairment of credit losses was $0.2 million in 2021 and 2020. At December 31, 2021, ATCO Gas had $3.4 million of trade receivables past due greater than 30 days (2020 - $5.5 million). No other impairments have been identified within accounts receivable or contract assets.

ATCO Gas has also entered into guarantee arrangements with Direct Energy's parent company(NRG Energy) relating to the retail energy supply functions performed by Direct Energy (see Note 21).

LIQUIDITY RISK

Liquidity risk is the risk that ATCO Gas will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from ATCO Gas' general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of ATCO Gas’ cash requirements. Additional cash requirements are met with the use of existing cash balances, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Line of credit

ATCO Gas has a line of credit available of $10.0 million (2020 - $10.0 million). The credit line enables ATCO Gas to obtain financing for general business purposes. At December 31, 2021 and 2020, no amounts were used under the line of credit.

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities at December 31, 2021, of ATCO Gas' financial liabilities based on the contractual undiscounted cash flows.

	2022	2023	2024	2025	2026	2027 and thereafter
Bank indebtedness	403	–	–	–	–	–
Short-term advances from parent company	121,800	–	–	–	–	–
Accounts payable and accrued liabilities	215,989	–	–	–	–	–
Accounts payable to parent and affiliate companies	34,660	–	–	–	–	–
Long-term debt:						
Principal	26,803	43,629	–	–	–	1,711,000
Interest expense	74,727	71,322	69,963	69,963	69,963	1,250,377
	474,382	114,951	69,963	69,963	69,963	2,961,377

The table below analyzes the remaining contractual maturities at December 31, 2020, of ATCO Gas' financial liabilities based on the contractual undiscounted cash flows.

	2021	2022	2023	2024	2025	2026 and thereafter
Bank indebtedness	2,074	–	–	–	–	–
Short-term advances from parent company	20,000	–	–	–	–	–
Accounts payable and accrued liabilities	209,473	–	–	–	–	–
Accounts payable to parent and affiliate companies	20,028	–	–	–	–	–
Long-term debt:						
Principal	20,000	26,803	43,629	–	–	1,631,000
Interest expense	75,041	72,188	68,783	77,843	64,364	1,247,726
	346,616	98,991	112,412	77,843	64,364	2,878,726

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact ATCO Gas by causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the operations of ATCO Gas.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the business of ATCO Gas.

While the investments of ATCO Gas are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on ATCO Gas remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, ATCO Gas has been following recommendations by local and federal public health authorities to adjust operational requirements as needed to ensure a coordinated approach across operations of ATCO Gas. As a result of these efforts and the experience in crisis response, the operations, financial position and performance of ATCO Gas have not been significantly impacted for the year ended December 31, 2021.

CLIMATE CHANGE RISK

ATCO Gas manages climate risks related to assets, including preparing for, and responding to, extreme weather events through activities such as proactive route and site selection, asset hardening, regular maintenance, and insurance. ATCO Gas follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital expenditures or acquiring assets, ATCO Gas considers site specific climate and weather factors, such as flood plain mapping and extreme weather history.

ATCO Gas also continues to explore and implement opportunities in energy efficiency. This process is associated with risks and uncertainties, and is highly dependent on changes in legislation, market price volatility, local and global demand on energy, as well as the timing of when the local and global markets transition to a more energy efficient and cleaner fuels-based economy. The extent and significance of the future impact of such risks and uncertainties remain unknown.

19. CAPITAL DISCLOSURES

ATCO Gas' objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for ATCO Gas. In October 2020, ATCO Gas received the 2021 Generic Cost of Capital Decision. The decision established a common equity ratio of 37.0 per cent for 2021, consistent to what was previously approved.

ATCO Gas includes share owner’s equity, preferred shares, and long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 3 and 24), in its determination of capitalization. In maintaining or adjusting its capital structure, ATCO Gas may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares and long-term debt.

20. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in ATCO Gas’ overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. ATCO Gas continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made in order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

ATCO Gas makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Income taxes

ATCO Gas makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of natural gas. The estimate is derived from unbilled gas distribution services supplied to customers. This estimate is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. ATCO Gas makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on ATCO Gas' past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, and the potential for technological obsolescence.

Impairment of long-lived assets

ATCO Gas continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, ATCO Gas estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Leases

Useful lives of right-of-use assets are based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, ATCO Gas identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

Retirement benefits

ATCO Gas, together with Canadian Utilities Limited and its subsidiary companies, consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds.

Since the discount rate is based on current yields, it is only a proxy for future yields. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 12.

Asset retirement obligations

ATCO Gas estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

Use of judgments and estimates around the COVID-19 pandemic

For the year ended December 31, 2021, ATCO Gas performed an assessment of the impacts of uncertainties around the COVID-19 pandemic on its financial position, financial performance and cash flows. The assessment required use of judgments and estimates and resulted in no material impacts to the financial statements.

21. CONTINGENCIES

Measurement inaccuracies

Measurement inaccuracies occur from time to time on gas metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

Direct Energy Partnership retail obligation

In 2004, ATCO Gas and its affiliate, ATCO Electric, transferred their retail energy supply businesses to Direct Energy Partnership (Direct Energy). The legal obligations of ATCO Gas and ATCO Electric for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric, with no refund of the transfer proceeds to Direct Energy.

NRG Energy Inc. (NRG), Direct Energy's parent company, provided a $300 million guarantee, supported by a $300 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

Other

ATCO Gas is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the financial statements.

22. COMMITMENTS

In addition to commitments disclosed elsewhere in the financial statements, ATCO Gas has entered into a number of agreements relating to transmission services, operating and maintenance, IT services and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter
Purchase obligations:						
Transmission services agreements	268,300	287,800	248,800	33,400	32,100	92,200
Operating and maintenance agreements	5,106	_	_	_	_	_
Information technology services	9,848	9,762	9,282	3,090	_	_
Capital expenditures	65,779	_	_	_	_	_
	349,033	297,562	258,082	36,490	32,100	92,200

23. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Gas entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2021	2020
ATCO Pipelines	Division of AGPL	Contract services	Revenues	**15,215**	16,561
		Contract services	Plant and equipment maintenance	**625**	1,783
		Transfer of assets	Property, plant and equipment	**5,799**	2,062
		Transfer of assets	Deferred revenue	**2,486**	–
		Contract services	Property, plant and equipment	**535**	597
ATCO Electric Ltd.	Affiliate	Rent and fleet services	Revenues	**1,199**	1,320
		Contract services	Revenues	**141**	–
		Rent and contractor	Other expenses	**505**	482
		Customer collections	Operating expenses	**354**	379
		Contract services	Property, plant and equipment	**971**	588
Northland Utilities Limited - NWT	Affiliate	Contract services	Revenues	**3**	3
Yukon Electrical	Affiliate	Contract services	Revenues	**27**	22
ATCO Power (2010)	Affiliate	Contract services	Revenues	**819**	284
		Contract services	Other expenses	**1,619**	–
ATCO Structures and Logistics Ltd.	Affiliate	Contract services	Revenues	**7**	–
ATCO Energy Solutions Ltd.	Affiliate	Contract services	Revenues	**202**	237
		Contract services	Office services	**–**	44
		Contract services	Property, plant and equipment	**–**	56
ATCO Energy Ltd.	Affiliate	Contract services	Revenues	**22**	22
		Retail services	Revenues	**80,146**	67,667
		Distribution service costs	Other expenses	**996**	864
		Contract services	Office services	**1**	1
ATCO Infrastructure Solutions Ltd.	Affiliate	Contract services	Revenues	**157**	–
		Contract services	Other expenses	**–**	1
Ashcor	Affiliate	Contract services	Revenues	**128**	23
Workforce Housing CA	Affiliate	Contract services	Revenues	**–**	1
ATCO Ltd. / CUL / CU Inc.	Parent	Contract services	Revenues	**492**	153
		Administration, rent and aircraft	Property, plant and equipment	**7,613**	8,671
		Administration, rent and aircraft	Other expenses	**36,781**	30,901
		Licensing fees	Other expenses	**3,033**	2,136
		Long term, short term interest expense and guarantee fees	Interest expense	**76,693**	77,280

Affiliate companies are subsidiaries of ATCO Gas' parent or ultimate parent.

ATCO Gas incurred $0.1 million (2020 - $0.1 million) in advertising and promotion expenses from an entity related through common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2021	2020
Receivables from related parties (1)	Accounts receivable from parent and affiliate companies	**5,069**	4,944
Payables to related parties (1)	Accounts payable to parent affiliate companies	**34,660**	20,028
Short-term advances (2)	Short-term advances from parent company	**121,800**	20,000
Long-term advances *(Note 11)*	Long-term debt to parent company	**1,771,589**	1,711,777
Equity preferred shares *(Note 14)*	Equity preferred shares to parent company	**64,273**	88,318

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

24. ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

ATCO Gas is regulated by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing, and service area.

ATCO Gas is under a form of rate regulation called Performance Based Regulation (PBR).

The current PBR period applies for a period of five years from 2018 to 2022. PBR allows distribution utilities the opportunity to recover prudently incurred costs of providing regulatory services and generate a fair return on investment. Under PBR, revenue is determined by a formula that adjusts customer rates for inflation and expected productivity improvements over a five year period.

Specifically, the PBR formula incorporates the following factors:

- Estimated annual inflation for input prices (I Factor)
- Less an offset to reflect expected productivity improvements during the PBR plan period (X Factor)

PBR also includes mechanisms to allow ATCO Gas to:

- Recover capital expenditures not recoverable through the PBR formula that meet certain criteria (K Factor)
- Recover from or refund to customers amounts outside of management's ability to control, that are material, should not have significantly influenced the I Factor, are prudently incurred, are recurring and could vary greatly from year to year (Y Factor) or are unforeseen and unlikely to recur (Z Factor).

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that ATCO Gas is eligible to adopt, ATCO Gas does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, ATCO Gas records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Natural gas distribution

Revenue from distribution of natural gas is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated natural gas is based on tariff-approved rates established by the Natural Gas Exchange and rates stipulated in the contracts, respectively. ATCO Gas recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to ATCO Gas for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the AUC. Franchise fee revenues and expenses are, therefore, recognized separately and are not recorded on a net basis.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when ATCO Gas can no longer withdraw the offer of those benefits and when ATCO Gas recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which ATCO Gas operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset’s carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to ATCO Gas and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

ATCO Gas allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Gas distribution plant and equipment	6 to 57 years	42 years	2.4 %
Buildings	12 to 42 years	39 years	2.6 %
Other plant, equipment and machinery	10 to 42 years	16 years	6.3 %

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. ATCO Gas amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and no longer than 80 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the statements of earnings.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

PROVISIONS

ATCO Gas recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event,

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of ATCO Gas. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, included in other liabilities, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

ATCO Gas classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on ATCO Gas' business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. ATCO Gas' long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if ATCO Gas intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) ATCO Gas has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, canceled, or expired.

Fair value hierarchy

ATCO Gas uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

ATCO Gas applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by ATCO Gas and recognizing the disposal of an asset on the day it is delivered by ATCO Gas. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, ATCO Gas assesses whether there evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

ATCO Gas applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, ATCO Gas estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

ATCO Gas participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the registered defined benefit plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, ATCO Gas is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2020.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. ATCO Gas does not have any liability to the Group Plan other than the minimum funding requirements of its subsidiaries. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

ATCO Gas participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and ATCO Gas accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. ATCO Gas, together with Canadian Utilities Limited and its subsidiary companies, consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, ATCO Gas is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2021, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

ATCO

May 13, 2022

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Attention: Kristjana Kellgren,
Executive Director, Rates Division

Re: ATCO Pipelines
AUC Rule 005
Annual Reporting of Financial and Operational Results

In accordance with the Alberta Utilities Commission (AUC or the Commission) Rule 005, please find enclosed ATCO Pipelines' 2021 Annual Reporting of Financial and Operational Results.

Should you have any questions or require further information regarding this submission, please do not hesitate to contact the undersigned at lisa.brennand@atco.com.

Yours truly,

Lisa Brennand, CPA, CA
Director, Regulatory

ATCO PIPELINES
SUMMARY OF REVENUE REQUIREMENT
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.	Description	Cross-Reference	2021 Actual	2020 Actual	Variance to Actual Col.[a]-[b]	
			[a]	[b]	[c] $	[d] %
1	Return on Rate Base	Sch 2	138,065	133,519	4,546	3.40
2	Operating and Maintenance Expense	Sch. 3	67,884	69,159	(1,275)	(1.84)
3	Taxes Other than Income	Sch. 10	19,768	17,960	1,808	10.07
4	Depreciation & Amortization Expense	Sch. 4	101,632	92,720	8,912	9.61
5	Income Taxes	Sch. 5	(5,173)	(9,063)	3,890	(42.92)
6	Total Utility Revenue Requirement		322,176	304,295	17,881	5.88
	Detailed Revenue					
7	Rate Revenue	Sch. 6	314,517	304,044	10,473	3.44
8	Franchise Fee Revenue	Sch. 6	4,692	3,736	956	25.59
9	Other Revenues	Sch. 6	2,967	(3,485)	6,452	(185.14)
10	**Total Revenues**	Sch. 6	322,176	304,295	17,881	5.88

Note:

The Approved forecast for 2021 can be found in Proceeding ID 27053 (Decision 27053-D01-2022). The 2020 Approved forecast can be found in Proceeding ID 25789 (Decision 25789-D01-2020).

ATCO PIPELINES
SUMMARY OF RETURN ON RATE BASE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross Ref.	Mid Year Capital	Ratios	Mid Year Rate Base	Cost Rate Percentage	Return Component [c]x[d]
			[a]	[b]	[c]	[d]	
	2021 Actual						
1	Long Term Debt	Sch 2.3	1,432,376	61.69%	1,446,401	4.06	58,724
2	Preferred Shares	Sch 2.4	30,320	1.31%	30,715	4.25	1,305
3	Common Equity	Sch 2.2, 11	848,138	37.00%	867,512	9.00	78,036
4	Totals	Sch. 2.1	2,310,834	100.00%	2,344,628	5.89	138,065

ATCO PIPELINES
SUMMARY OF MID-YEAR RATE BASE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross Reference	2021 Actual [a]	2020 Actual [b]	Variance to Actual Col.[a]-[b] [c] $	[d] %	
	Property, Plant and Equipment						
1	Opening Balance		3,251,484	3,057,601	193,883	6.3	
2	Capital Expenditures	Sch 4.2	364,185	208,820	155,365	74.4	**(1)**
3	Inter-company Transfers	Sch 4.1	(7,888)	3,198	(11,086)	(346.7)	**(2)**
4	Adjustments	Sch 4.1	0	0	0	0.0	
5	Retirements	Sch 4.1	(20,485)	(18,135)	(2,350)	13.0	**(3)**
6	Closing Balance	Sch 4.1	3,587,296	3,251,484	335,812	10.3	
7	**Mid-Year PPE**		**3,419,390**	**3,154,543**	**264,847**	**8.4**	
	Accumulated Depreciation						
8	Opening Balance		898,337	833,020	65,317	7.8	
9	Depreciation Expense	Sch 4	105,531	96,541	8,990	9.3	**(4)**
10	Retirements	Sch 4.1	(20,485)	(18,135)	(2,350)	13.0	**(3)**
11	Inter-company Transfers	Sch 4.1	(3,100)	1,016	(4,116)	(405.1)	**(2)**
12	Depreciation Capitalized	Sch 4	1,184	1,010	174	17.2	
13	Adjustments	Sch 4.1	0	32	(32)	(100.0)	
14	Proceeds on Disposal of Assets	Sch 4.1	253	168	85	50.6	
15	Net Salvage Costs	Sch 4.1	(12,516)	(15,315)	2,799	(18.3)	**(5)**
16	Closing Balance	Sch 4.1	969,204	898,337	70,867	7.9	
17	**Mid-Year Accumulated Depreciation**		**933,771**	**865,679**	**68,092**	**7.9**	
18	**Mid-Year Work in Progress (CWIP/RWIP)**	Sch 4.1	**(53,716)**	**(153,337)**	**99,621**	**(65.0)**	
	Contributions in Aid of Construction						
19	Opening Balance		223,318	210,281	13,037	6.2	
20	Closing Balance		231,215	223,318	7,897	3.5	
21	**Mid-Year Contributions in Aid of Construction**		**227,267**	**216,800**	**10,467**	**4.8**	
	Amortization of Contributions						
22	Opening Balance		64,765	60,941	3,824	6.3	
23	Closing Balance		68,385	64,765	3,620	5.6	
24	**Mid-Year Amortization of Contributions**		**66,575**	**62,853**	**3,722**	**5.9**	
	Unapplied Contributions						
25	Opening Balance		2,902	4,762	(1,860)	(39.1)	
26	Closing Balance		1,101	2,902	(1,801)	(62.1)	
27	**Mid-Year Unapplied Contributions**		**2,002**	**3,832**	**(1,830)**	**(47.8)**	
28	**Mid-Year Plant in Service**		**2,273,213**	**1,985,412**	**287,801**	**14.5**	
	Necessary Working Capital						
29	Cash Expenses		1,870	1,730	140	8.1	
30	Financial Items		15,118	15,011	107	0.7	
31	Assets Held For Sale		31,975	0	31,975	0.0	**(6)**
32	Unamortized Debt and Preferred Discount		8,276	7,483	793	10.6	
33	Materials and Supplies		268	210	58	27.6	
34	Line Pack		3,722	3,617	105	2.9	
35	Salt Cavern Peaking Working Gas		7,276	6,886	390	5.7	
36	Future Income Tax		(250,018)	(221,548)	(28,470)	12.9	
37	Future Income Tax Regulatory Asset		252,928	224,280	28,648	12.8	
38	Total Adjustments		71,415	37,669	33,746	89.6	
39	Mid-Year Rate Base	Sch 2.0	2,344,628	2,023,081	321,547	15.9	

Notes:

(1) Please refer to Schedule 4.2.

(2) 2021 Actual is lower than prior year mainly due to asset transfers between ATCO Pipelines and ATCO Gas associated with the Urban Pipelines Replacement (UPR) Program.

(3) 2021 Actual is higher than prior year mainly due to higher Transmission Plant retirements, partially offset by fewer Machinery & Equipment and Straight Line (Dedicated) retirements.

(4) Please refer to Schedule 4.0

(5) 2021 Actual is lower than prior year mainly due to fewer Improvement & Replacement Removal projects being completed.

(6) 2021 Actual is higher than prior year due to costs incurred for the segment of Pioneer Pipeline that was sold to NGTL in 2022.

ATCO PIPELINES
SUMMARY OF MID YEAR CAPITAL STRUCTURE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross Ref.	Current Year End	Previous Year End	Actual Mid Year Capital
	2021 Actual				
1	Long Term Debt	Sch 2.3	1,522,285	1,342,466	1,432,376
2	Preferred Shares	Sch 2.4	24,500	36,139	30,320
3	Common Equity	Sch 11	887,399	808,876	848,138
4	Total Mid Year Invested Capital		2,434,184	2,187,481	2,310,834

ATCO PIPELINES
SCHEDULE OF DEBT CAPITAL EMPLOYED
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

2021 ACTUAL:

LINE	CROSS REF	ISSUE DATE	MATURITY DATE	COUPON RATE %	PRINCIPAL	UNDERWRITING DISCOUNT AND EXPENSES	TOTAL AMOUNT	EFFECTIVE COST RATE %	CARRYING COSTS	Average Embedded Cost Rate
		Debentures								
1		91-12-18	2022	9.92	13,197	2	13,195	10.15	1,339	
2		92-12-08	2023	9.40	16,371	8	16,363	9.51	1,556	
3		04-11-18	2034	5.89	21,900	56	21,844	5.94	1,298	
4		05-11-21	2035	5.18	69,000	210	68,790	5.23	3,598	
5		06-11-20	2036	5.03	39,000	118	38,882	5.07	1,971	
6		07-11-30	2037	5.56	20,000	64	19,936	5.60	1,116	
7		08-05-26	2038	5.58	30,000	105	29,895	5.62	1,680	
8		08-05-26	2028	5.56	20,000	42	19,958	5.61	1,120	
9		09-03-06	2039	6.50	4,000	16	3,984	6.55	261	
10		09-03-06	2024	6.22	4,000	4	3,996	6.28	251	
11		11-10-24	2041	4.54	57,100	237	56,863	4.58	2,604	
12		11-10-24	2061	4.59	22,900	115	22,785	4.62	1,053	
13		12-09-11	2042	3.81	25,000	107	24,893	3.84	956	
14		12-09-11	2062	3.83	10,000	52	9,948	3.85	383	
15		12-11-14	2052	3.86	8,000	38	7,962	3.89	310	
16		13-09-28	2043	4.72	60,000	270	59,730	4.76	2,843	
17		14-09-28	2044	4.09	65,000	295	64,705	4.12	2,666	
18		14-10-17	2054	4.09	20,000	106	19,894	4.13	822	
19		15-07-27	2045	3.96	100,000	506	99,494	4.00	3,980	
20		15-10-30	2055	4.21	20,000	111	19,889	4.24	843	
21		16-11-17	2046	3.76	110,000	645	109,355	3.80	4,155	
22		17-11-22	2047	3.54	155,000	944	154,056	3.58	5,515	
23		18-11-21	2048	3.95	120,000	771	119,229	3.99	4,757	
24		19-09-05	2049	2.96	215,000	1,282	213,718	3.00	6,412	
25		20-09-28	2050	2.61	85,000	609	84,391	2.64	2,228	
26		21-09-03	2051	3.17	220,000	1,470	218,530	3.21	7,015	
27		Current Year-End Balance			1,530,468	8,183	1,522,285		60,732	3.99%
28		Prior Year-End Balance					1,342,466		55,596	4.14%
29	Sch. 2	Mid-Year Balance					1,432,376		58,164	4.06%

Note:
In accordance with Commission Direction 4 in Decision 22570-D01-2018, the 2021 Actual debt rate cost is 4.08%.

ATCO PIPELINES
SCHEDULE OF PREFERRED SHARE CAPITAL EMPLOYED
MID YEAR CAPITAL STRUCTURE
(THOUSANDS OF DOLLARS)

2021 ACTUAL:

LINE	CROSS REF	SERIES	ISSUE DATE	DIVIDEND RATE	STATED VALUE OF ISSUE (1)	UNDERWRITING DISCOUNT AND EXPENSES	NET PROCEEDS OUTSTANDING	CARRYING COSTS OF ISSUE	AVERAGE EMBEDDED COST RATE
		Non Retractable							
		Cumulative Redeemable Second Preferred Shares							
1		V	1997	4.60%	0	0	0	0	0.00%
2		1	2007	4.60%	20,000	0	20,000	920	4.60%
3		4	2010	2.29%	4,500	0	4,500	103	2.29%
4		Total Current Year-End Balance			24,500	0	24,500	1,023	4.18%
5		Prior Year-End Balance					36,139	1,556	4.31%
6	Sch. 2	Mid-Year Balance					30,320	1,290	4.25%

Note: Series V Preferred Shares were redeemed in 2021.
Series 4 Preferred Shares reset in 2021.

ATCO PIPELINES
RECONCILIATION
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		2021 Actual
1	Return of Mid-year rate base financed by common equity	78,036
2	Return on book value of common equity as per financial statements	59,088
3	**Difference**	**18,948**
4		
	Reconciliation	
5	Common Equity Return of Mid-year rate base financed by common equity	78,036
6	Long-Term Debt - Schedule 2.0	58,724
7	Preferred Shares - Schedule 2.0	1,305
8	**Subtotal - Utility Income**	**138,065**
9	Interest and Other Expense	(57,907)
10	Rate Regulated Activities (See Note 3 of the Financial Statements)	(19,538)
11	AFUDC to IDC Difference	1,129
12	Non-Utility Expense	(3,819)
13	Other	1,158
14	**Return on book value of common equity as per financial statements**	**59,088**

ATCO PIPELINES
SUMMARY OF OPERATING AND MAINTENANCE EXPENSE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Ref.	2021 Actual [a]	2020 Actual [b]	Variance to Actual Col.[a]-[b] $	[d] %	
	Operating & Maintenance Expense						
1	Underground Storage		1,147	1,291	(144)	(11.2)	
2	Transmission		34,637	36,533	(1,896)	(5.2)	
3	Administration and General		36,022	33,519	2,503	7.5	
5	Total Operating & Maintenance Expense		71,806	71,343	463	0.7	
6	Less: Disallowed O&M		3,922	2,184	1,738	79.6	**(1)**
7	Operating & Maintenance Expense - Net	Sch 1	67,884	69,159	(1,275)	(1.8)	

Notes:
(1) 2021 Actual is higher than 2020 Actual mainly due to an increase in the disallowed portion of head office costs and signature rights.

ATCO PIPELINES
SUMMARY OF DEPRECIATION EXPENSE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Reference	2021 Actual	2020 Actual	Variance to Actual Col.[a]-[b]		
			[a]	[b]	[c]	[d] %	
	Depreciation Expense						
1	Underground Storage Plant	Sch 4.1	1,840	1,822	18	1.0	
2	Transmission Plant	Sch 4.1	95,311	86,701	8,610	9.9	**(1)**
3	General Plant	Sch 4.1	1,223	1,251	(28)	(2.2)	
4	Office Furniture & Equipment	Sch 4.1	234	235	(1)	(0.4)	
5	Machinery & Equipment	Sch 4.1	3,657	3,396	261	7.7	
6	Leasehold Improvements	Sch 4.1	101	96	5	5.2	
7	Software	Sch 4.1	3,162	2,853	309	10.8	
8	Straight Line (Dedicated)	Sch 4.1	1,187	1,197	(10)	(0.8)	
9	Capitalized Depreciation		(1,184)	(1,010)	(174)	17.2	
10	Sub-total	Sch 4.1	105,531	96,541	8,990	9.3	
	Amortization of Contributions						
11	Underground Storage Plant		(3.00)	(4.00)	1.00	(25.00)	
12	Transmission Plant		(3,871.00)	(3,799.00)	(72.00)	1.90	
13	General Plant		(7.00)	-	(7.00)	-	
14	Straight Line (Dedicated)		(18.00)	(18.00)	-	-	
15	Sub-total		(3,899)	(3,821)	(78)	2.0	
16	**Net Depreciation Expense - Utility**		101,632	92,720	8,912	9.6	

Notes

(1) 2021 Actual Transmission Plant depreciation expense is higher than 2020 Actual mainly due to the higher opening depreciable base, as well as the Pioneer Pipeline Acquisition in 2021.

ATCO PIPELINES
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

CAPITAL ASSETS

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Additions	2021 Retirements	2021 Removals	2021 Transfers	2021 Proceeds	2021 Adjustments	Balance at 12/31/2021
1	Underground Storage Plant		60,058	3,211	(1,024)	0	0	0	0	62,245
2	Transmission Plant		2,913,251	383,693	(16,252)	0	(7,888)	0	0	3,272,804
3	General Plant		39,759	986	(374)	0	0	0	0	40,371
4	Office Furniture & Equipment		5,219	54	(118)	0	0	0	0	5,155
5	Machinery & Equipment		34,188	5,516	(1,391)	0	0	0	0	38,313
6	Leasehold Improvements		2,499	19	0	0	0	0	0	2,518
7	Software		23,472	4,948	(981)	0	0	0	0	27,439
8	Straight Line (Dedicated)		105,796	0	(345)	0	0	0	0	105,451
9	**Subtotal**		3,184,242	398,427	(20,485)	0	(7,888)	0	0	3,554,296
10	Capital Work in Progress (CWIP)		67,242	(34,242)	0	0	0	0	0	33,000
11	**Total Utility**	Sch 2.1	3,251,484	364,185	(20,485)	0	(7,888)	0	0	3,587,296

ACCUMULATED DEPRECIATION

Line No.	Property Group	Cross-Reference	Balance at 12/31/2020	2021 Depreciation Provision	2021 Retirements	2021 Removals	2021 Transfers	2021 Proceeds	2021 Adjustments	Balance at 12/31/2021
12	Underground Storage Plant		39,250	1,840	(1,024)	(119)	0	0	505	40,452
13	Transmission Plant		729,427	95,311	(16,252)	(12,390)	(3,100)	36	(603)	792,429
14	General Plant		10,319	1,223	(374)	(143)	0	0	0	11,025
15	Office Furniture & Equipment		1,978	234	(118)	0	0	0	0	2,094
16	Machinery & Equipment		15,353	3,657	(1,391)	(18)	0	217	0	17,818
17	Leasehold Improvements		2,026	101	0	(1)	0	0	0	2,126
18	Software		8,568	3,162	(981)	0	0	0	98	10,847
19	Straight Line (Dedicated)		95,088	1,187	(345)	0	0	0	0	95,930
20	**Subtotal**		902,009	106,715	(20,485)	(12,671)	(3,100)	253	0	972,721
21	Removal Work in Progress (RWIP)		(3,672)	0	0	155	0	0	0	(3,517)
22	**Total Utility**	Sch 2.1	898,337	106,715	(20,485)	(12,516)	(3,100)	253	0	969,204

ATCO PIPELINES
SUMMARY OF CAPITAL EXPENDITURES
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Ref	2021 Actual [a]	2020 Actual [b]	Variance to Actual Col.[a]-[b] [c]	[d] %	
	General Production Transmission						
1	Major Projects		66,198	88,985	(22,787)	(25.6)	**(1)**
2	General		288,524	110,080	178,444	162.1	**(2)**
3	Sub-Total		354,722	199,065	155,657	78.2	
	Land and Structures						
4	General		979	166	813	489.8	
	Moveable Equipment						
5	General		2,318	2,344	(26)	(1.1)	
6	Software Development		4,658	5,708	(1,050)	(18.4)	**(3)**
7	Sub-Total		6,976	8,052	(1,076)	(13.4)	
8	Other		1,508	1,537	(29)	(1.9)	
9	**Capital Expenditures**	Sch 4.1	364,185	208,820	155,365	74.4	

Notes:

(1) 2021 Actual is lower than 2020 Actual primarily due to the completion of the Pembina Keephills project in 2020.

(2) 2021 Actual is higher than 2020 Actual primarily due to the acquisition of the Pioneer Pipeline in 2021.

(3) 2021 Actual is lower than 2020 Actual mainly due to implementation of the Competency Based Work Scheduling (CBWS) program in 2020.

ATCO PIPELINES
SUMMARY OF UTILITY INCOME TAX
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		2021 Actual	2020 Actual	Variance to Actual	
		[a]	[b]	[c] $	[d] %
1	Net Income Before Tax - Fed	74,168	72,121	2,047	2.84
2	Total Permanent Differences - Fed	(1,750)	(1,950)	200	(10.26)
3	Total Timing Differences - Fed	(95,032)	(105,834)	10,802	(10.21)
4	Total Differences - Fed	(96,782)	(107,784)	11,002	(10.21)
5	Taxable Income - Fed	(22,614)	(35,663)	13,049	(36.59)
6	Net Income Before Tax - Prov	74,168	72,121	2,047	2.84
7	Total Permanent Differences - Prov	(1,750)	(1,950)	200	(10.26)
8	Total Timing Differences - Prov	(95,054)	(105,834)	10,780	(10.19)
9	Total Differences - Prov	(96,804)	(107,784)	10,980	(10.19)
10	Taxable Income - Prov	(22,636)	(35,663)	13,027	(36.53)
11	Federal Income Tax Rate	15%	15%		
12	Total Federal Income Tax	(3,392)	(5,349)	1,957	(36.59)
13	Provincial Income Tax Rate	8%	9%		
14	Total Provincial Income Tax	(1,811)	(3,210)	1,399	(43.58)
15	Current Tax Payable	(5,203)	(8,559)	3,356	(39.21)
16	Large Corporation and Other Tax	-	-	-	-
17	Prior Year (over)/under provisions	(1,349)	(1,057)	(292)	27.63
18	Current Year (over)/under provisions	-	-	-	-
19	Other	522	594	(72)	(12.12)
20	Current Income Tax	(6,030)	(9,022)	2,992	(33.16)
21	Deferred Tax (please describe)	857	(41)	898	(2,190.24)
22	Corporate Income Tax	(5,173)	(9,063)	3,890	(42.92)
23	Utility Income Tax	(5,173)	(9,063)	3,890	(42.92)

Other Information

In accordance with Commission Direction 2 in Decision 22570-D01-2018, the unfunded FIT liability is $265.2M for 2021 and $239.5M for 2020, the year-over-year change is $25.7M.

ATCO PIPELINES
SUMMARY OF SALES REVENUES BY CLASSIFICATION
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Ref	2021 Actual [a]	2020 Actual [b]	Variance to Actual Col.[a]-[b] [c]	[d] %	
1	Total Transportation Revenue		314,517	304,044	10,473	3.4	
2	Revenue Adjustments		2,149	(4,595)	6,744	(146.8)	
3	Franchise Fee Revenue		4,692	3,736	956	25.6	
4			6,841	(859)	7,700	(896.4)	
	OTHER REVENUE						
5	Other Miscellaneous Revenue		818	1,110	(292)	(26.3)	
6	Total Other Revenue		818	1,110	(292)	(26.3)	
7	**TOTAL UTILITY REVENUE**		322,176	304,295	17,881	5.9	**(1)**

Note:

(1) 2021 Actual is higher than 2020 Actual primarily due to an increase in revenue requirement mainly attributed to the purchase of Pioneer Pipeline in 2021.

ATCO PIPELINES
EXPLANATION OF TRANSACTIONS
WITH AFFILIATED COMPANIES
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.	Affiliate	Nature of Service	Recorded As	2021 Actual
1	ATCO Ltd. / CUL / CU Inc.	Contract Services	Revenue	(3)
2				
3		License fees	Operating	1,199
4				
5		Administration, rent and aircraft	Operating	11,391
6				
7		Administration, rent and aircraft	Capital	2,263
8				
9	ATCO Gas	Financial, engineering, operations, corporate, facilities		
10		and rent services	Revenue	(2,171)
11				
12		Engineering and construction services	Operating	3,654
13				
14		Engineering and construction services	Capital	11,561
15				
16		Transfer of Assets	Capital	2,302
17				
18	ATCO Energy Solutions	Fees for purchase/sale of Salt Cavern gas	Operating	25
19				
20		Contract Services	Revenue	(971)
21				
22	ATCO Pipelines S.A. de C.V.	Engineering and construction services	Revenue	(172)
23				
24	IEIE S.A. de C.V.	Engineering and construction services	Revenue	(202)
25				
26	ATCO Investments Solutions	Facilities Management	Operating	69
27				
28	ATCO Electric	Contract services	Capital	298
29				
30		Contract services	Operating	19
31				
32	ATCO Power	Contract services	Revenue	(174)
33				
34	ATCO Infrastructure Solutions PR	Contract Services	Capital	94

ATCO PIPELINES TOTAL
SUMMARY OF PAYROLL AND MANPOWER STATISTICS
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Ref	2021 Actual [a]	2020 Actual [b]	Variance to Actual Col.[a]-[b] $	[e] %	
	Payroll Statistics						
1	Gross Salaries & Wages		63,024	51,164	11,860	23.2	**(1)**
	Manpower Statistics*						
2	Total Regular Employees		409	403	6	1.5	
3	Total Temporary Employees		36	24	12	50.0	
4	Total Contract Staff		0	0	0	0.0	
5	Total Manpower		445	427	18	4.2	
	Less:						
6	Allocated to Non-Regulated		1	1	0	0.0	
7	Total Manpower - Utility		444	426	18	4.2	
	Manpower Allocation by Division						
8	Operations and Maintenance		400	369	31	8.4	
9	Administration and General		45	58	(13)	(22.4)	
10	Total Manpower - Utility		445	427	18	4.2	

Notes:

* Full Time Equivalents (FTEs) are based on year end numbers.

(1) Gross Salaries & Wages are higher in 2021 than prior year mainly due to higher staffing levels and NGEA bargaining payments, and vaccine incentive payments.

ATCO PIPELINES
SUMMARY OF RESERVE/DEFERRAL ACCOUNTS
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

			2021 Actual				
Line No.	List of Reserve/Deferral Accounts	Cross-Ref	Opening Balance	Additions	Amort.	Recoveries	Closing Balance
1	Salt Cavern Deferral		1,234	(2,779)	-	-	(1,545)
2	Long Term Debt Rate Deferral		(5,443)	17	(272)	(5,429)	275
3	Defined Benefit Pension Deferral		(327)	(60)	357	(383)	(361)
4	VPP Deferral		(198)	1,729	1,677	(114)	(32)
5	Property Tax Deferral		0	14,621	13,510	-	1,111
6	Pandemic Cost Deferral		0	138	971	-	(833)
7	Total Regulated Deferrals		(4,734)	13,666	16,243	(5,926)	(1,385)
8	Injuries and Damages Reserve		(447)	385	(39)	-	(23)
9	Regulatory Expense Reserve		(733)	3,544	3,362	230	(781)
10	Total Regulated Reserves		(1,180)	3,929	3,323	230	(804)

ATCO PIPELINES
RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
INCOME SUMMARY
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Reference	2021 Financial Statements [a]	Adjustments [b]	2021 Utility Total [c]
1	**Total Revenue**	Sch 6	321,239	937	322,176
	Less:				
	Operating Expenses				
2	Operation and Maintenance	Sch 3	85,186	(17,302)	67,884
3	Depreciation and Amortization	Sch 4	81,086	20,546	101,632
4	Taxes Other than Income		19,768	-	19,768
5			186,040	3,244	189,284
	Financing Charges and Other				
6	Interest Expense	Sch 2	57,405	1,319	58,724
7	Other Expense		2,133	(2,133)	0
8	Interest and Other Income		(1,631)	1,631	0
9			57,907	817	58,724
10	**Net Earnings Before Tax**		77,292	(3,124)	74,168
11	Less:				
12	Income Taxes	Sch. 5	18,204	(23,377)	(5,173)
13	**Net Earnings after Tax**		59,088	20,253	79,341
14	Dividends on Preferred Shares	Sch 2	0	(1,305)	(1,305)
15	**Earnings attributable to Common Shares**		59,088	(24,682)	78,036
16	Opening Retained Earnings		570,663		
17			629,751		
18	Dividends on Common Shares		0		
19	Dividends on Preferred Shares		1,365		
20	Other		7		
21	OCI		(1,678)		
22	**Closing Retained Earnings**		630,057		

ATCO PIPELINES
RECONCILIATION OF FINANCIAL REPORTING SCHEDULES TO AUDITED FINANCIAL STATEMENTS
BALANCE SHEET
FOR YEAR ENDED DECEMBER 31, 2021
(THOUSANDS OF DOLLARS)

Line No.		Cross-Reference	2021 Financial Statements	Adjustments	2021 Utility Total
			[a]	[b]	[c]
	ASSETS				
	Current Assets				
1	Cash and short term advance to parent corporation		52,437	-	52,437
2	Accounts receivable		28,636	3,987	32,623
3	Accounts receivable from affiliates		6,815	-	6,815
4	Inventories		6,955	4,808	11,763
5	Income taxes recoverable		4,834	-	4,834
6	**Regulatory Assets**		-	2,242	2,242
7	Prepaid expenses and other		67,403	-	67,403
8			167,080		178,117
9	**Property, Plant and Equipment (Including Intangible Assets)**		2,663,989	(155,639)	2,508,350
10	**Regulatory Assets**		0	272,847	272,847
11	Deferred Financing Charges		8,877	-	8,877
12	**Other Assets**		8,722	(8,722)	-
13			2,848,668		2,968,191
	LIABILITIES AND CAPITALIZATION				
	Current Liabilities				
14	Bank indebtedness and short term advance from parent corporation		145,704	-	145,704
15	Accounts payable and accrued liabilities		30,360	(103)	30,257
16	Long-term debt		13,197	-	13,197
17	Accounts payable to parent and affiliate corporations		20,557	-	20,557
18			209,818		209,715
19	**Future income taxes**		208,954	53,778	262,732
20	**Regulatory liabilities**		-	57,107	57,107
21	**Other Deferred Credits**		174,547	(162,683)	11,864
22			383,501		331,703
	Capitalization				
23	Long-term debt		1,525,971	(11,043)	1,514,928
24	Equity preferred shares		24,094	352	24,446
25	Class A and Class B shares		75,226	(1,405)	73,821
26	Retained earnings		630,058	183,520	813,578
27			2,255,349		2,426,773
28			2,848,668		2,968,191

ATCO PIPELINES
SCHEDULE OF PENSION PLAN CONTRIBUTIONS
FOR YEAR ENDED DECEMBER 31, 2021
(MILLIONS OF DOLLARS)

ATCO Pipelines has provided the following information below in response to Direction 13 from AUC Decision 2010-189 which indicated:

The Commission would also like to establish the ability to monitor contributions into the Pension Plan. In this regard, the Commission directs ATCO Utilities in its respective annual Rule 005: Annual Reporting Requirements of Operational and Financial Results (Rule 005) filings to include the following information:

i) The amounts contributed to the Pension Plan on a calendar year basis by each of the ATCO Utilities (broken down by utility) and the amounts contributed by the unregulated companies participating in the Pension Plan collectively. In reporting these contributions, the report should separately identify, amounts contributed as service costs under each of the DB Plan and the DC Plan and amounts contributed in respect of the DB Plan unfunded liability.

2021 Actual		Defined Benefit Pension Expense		Defined Contribution Pension Expense	**Total**
		Service Amount	Special Payment	Service Amount	
ATCO Pipelines (Note 1)	**Total**	0.9	-	1.9	**2.8**
ATCO Unregulated (Note 1)	**Total**	2.5	-	6.1	**8.6**

Note 1 - The actual defined benefit pension expense, special payment and defined contribution service amount do not include amounts allocated from the ATCO Head Office.

ii) A reconciliation in respect of the previous calendar year, by utility, of amounts collected through rates in respect of pension funding obligations with amounts contributed to the pension plan including amounts in the deferral account approved in accordance with this Decision. Accordingly the deferral account should be calculated as the annual difference between the amounts collected in rates in respect of the special payments and the special payment amounts actually paid by ATCO Utilities pursuant to the Pension Valuation(s) accepted by the Superintendent of Pensions that were in force during such year.

<u>2020 Reconciliation (ATCO Pipelines)</u>	
2020 Special Payment Pension costs included in ATCO Pipelines' Revenue Requirement (Note 2)	**-**
2020 Actual Special Payment Pension contributions	**-**
2020 Actual Special Payment Pension contributions - allocated from ATCO Head Office	**-**
Refund/(collection) to / (from) customers	**-**

Note 2 - Per ATCO Pipelines 2021-2023 GRA Compliance Filing, Proceeding 26443

<u>2021 Reconciliation (ATCO Pipelines)</u>	
2021 Special Payment Pension costs included in ATCO Pipelines' Revenue Requirement (Note 3)	**-**
2021 Actual Special Payment Pension contributions	**-**
2021 Actual Special Payment Pension contributions - allocated from ATCO Head Office	**-**
Refund/(collection) to / (from) customers	**-**

Note 3 - Per ATCO Pipelines 2021-2023 GRA Compliance Filing, Proceeding 26443
Pension information can be found per ATCO Pipelines' 2021-2023 GRA filing. Exhibit 25663-X0001, Section 4.2.10 – Defined Benefit (DB) Pension

iii) Confirmation of the date of any actuarial valuation reports filed with the Superintendent of Pensions since the last Rule 005 filing, and the associated impact of any filings on the pension funding requirements of each of the ATCO Utilities.

The Mercer 2020 CU Pension Plan Report dated August 11, 2021 was filed with the Superintendent of Pensions.

(a division of ATCO Gas and Pipelines Ltd.)

ATCO PIPELINES

FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021

Independent auditor's report

To the Shareowner of ATCO Gas and Pipelines Ltd.

Our opinion

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., (the Division) as at December 31, 2021 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited
The Division's financial statements comprise:

- the statement of earnings for the year ended December 31, 2021;
- the statement of comprehensive income for the year ended December 31, 2021;
- the balance sheet as at December 31, 2021;
- the statement of changes in equity for the year ended December 31, 2021;
- the statement of cash flow for the year ended December 31, 2021; and
- the notes to the financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Division in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Stantec Tower, 10220 103 Avenue NW, Suite 2200, Edmonton, Alberta, Canada T5J 0K4
T: +1 780 441 6700, F: +1 780 441 6776

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Division's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Division or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Division's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Division's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Division's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to

the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Division to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Edmonton, Alberta
April 29, 2022

TABLE OF CONTENTS

STATEMENT OF EARNINGS

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Revenues	4	**321,239**	315,621
Costs and expenses			
Salaries, wages and benefits		**(27,758)**	(28,173)
Plant and equipment maintenance		**(28,770)**	(37,564)
Depreciation and amortization	9, 10	**(81,086)**	(74,728)
Franchise fees		**(4,692)**	(3,736)
Property and other taxes		**(15,076)**	(14,224)
Other	5	**(28,658)**	(31,782)
		(186,040)	(190,207)
Operating profit		**135,199**	125,414
Interest income		**–**	15
Interest expense	6	**(57,907)**	(52,693)
Net finance costs		**(57,907)**	(52,678)
Earnings before income taxes		**77,292**	72,736
Income taxes	7	**(18,204)**	(16,068)
Earnings for the year		**59,088**	56,668

See accompanying Notes to Financial Statements.

STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31	
(thousands of Canadian Dollars)	**Note**	**2021**	**2020**
Earnings for the year		**59,088**	56,668
Other comprehensive income (loss), net of income taxes			
Item that will not be reclassified to earnings:			
Re-measurement of retirement benefits [(1)]	12	**1,678**	(1,062)
Comprehensive income for the year		**60,766**	55,606

(1) Net of income taxes of $(0.5) million for the year ended December 31, 2021 (2020 - $0.3 million).

See accompanying Notes to Financial Statements.

BALANCE SHEET

(thousands of Canadian Dollars)	Note	December 31 2021	2020
ASSETS			
Current assets			
Cash		**437**	–
Short-term advances to parent company		**52,000**	–
Accounts receivable and contract assets	13	**28,636**	25,250
Accounts receivable from parent and affiliate companies	13, 23	**6,815**	6,010
Inventories	8	**6,955**	7,312
Income taxes recoverable		**4,834**	6,930
Prepaid expenses and other current assets		**67,403**	4,036
		167,080	49,538
Non-current assets			
Property, plant and equipment	9	**2,522,734**	2,254,350
Intangibles	10	**141,255**	134,513
Other assets		**8,722**	6,736
Total assets		**2,839,791**	2,445,137
LIABILITIES			
Current liabilities			
Bank indebtedness		–	581
Short-term advances from parent company	23	**145,704**	6,000
Accounts payable and accrued liabilities		**25,180**	32,756
Accounts payable to parent and affiliate companies	23	**20,557**	16,359
Long-term debt	11, 23	**13,197**	39,000
Provisions and other current liabilities	3	**5,180**	5,365
		209,818	100,061
Non-current liabilities			
Deferred income tax liabilities	7	**208,954**	183,621
Retirement benefit obligations	12	**15,599**	17,662
Customer contributions	13	**158,942**	152,662
Long-term debt	11, 23	**1,508,394**	1,302,793
Other liabilities		**8,707**	6,723
Total liabilities		**2,110,414**	1,763,522
EQUITY			
Equity preferred shares	14, 23	**24,094**	35,726
Class A and Class B share owner's equity			
Class A and Class B shares	15	**75,226**	75,226
Retained Earnings		**630,057**	570,663
		705,283	645,889
Total equity		**729,377**	681,615
Total liabilities and equity		**2,839,791**	2,445,137

See accompanying Notes to Financial Statements.

DIRECTOR

DIRECTOR

STATEMENT OF CHANGES IN EQUITY

(thousands of Canadian Dollars)	**Note**	**Class A and Class B Shares**	**Equity Preferred Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Income**	**Total Equity**
December 31, 2019		75,226	35,726	542,413	–	653,365
Earnings for the year		–	–	56,668	–	56,668
Other comprehensive loss		–	–	–	(1,062)	(1,062)
Loss on retirement benefits transferred to retained earnings	12	–	–	(1,062)	1,062	–
Dividends	14,15	–	–	(27,356)	–	(27,356)
December 31, 2020		75,226	35,726	570,663	–	681,615
Earnings for the year		–	–	**59,088**	–	**59,088**
Other comprehensive income		–	–	–	**1,678**	**1,678**
Gain on retirement benefits transferred to retained earnings	12	–	–	**1,678**	**(1,678)**	–
Redemption of equity preferred shares to parent company	14	–	**(11,632)**	**(7)**	–	**(11,639)**
Dividends	14,15	–	–	**(1,365)**	–	**(1,365)**
December 31, 2021		**75,226**	**24,094**	**630,057**	–	**729,377**

See accompanying Notes to Financial Statements.

STATEMENT OF CASH FLOW

(thousands of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Operating activities			
Earnings for the year		**59,088**	56,668
Adjustments to reconcile earnings to cash flows from operating activities	16	**171,319**	165,792
Changes in non-cash working capital	16	**800**	(1,929)
Cash flows from operating activities		**231,207**	220,531
Investing activities			
Additions to property, plant and equipment		**(348,362)**	(186,290)
Additions to intangibles		**(11,814)**	(13,078)
Changes in non-cash working capital	16	**(9,818)**	(163)
Other		**(58,140)**	(2,497)
Cash flows used in investing activities		**(428,134)**	(202,028)
Financing activities			
Issue of long-term debt	11	**220,000**	85,000
Repayment of long-term debt	11	**(39,000)**	(11,262)
Redemption of equity preferred shares	14	**(11,639)**	–
Dividends paid on equity preferred shares	14	**(1,365)**	(1,556)
Dividends paid to Class A and Class B share owner	15	**–**	(25,800)
Interest paid		**(55,837)**	(54,468)
Other		**(1,918)**	(830)
Cash flows from (used in) financing activities		**110,241**	(8,916)
Increase in cash position		**(86,686)**	9,587
Beginning of year		**(6,581)**	(16,168)
End of year	16	**(93,267)**	(6,581)

See accompanying Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2021

(Tabular amounts in thousands of Canadian Dollars, except as otherwise noted)

1. THE DIVISION AND ITS OPERATIONS

ATCO Pipelines ("ATCO Pipelines") and ATCO Gas are divisions of ATCO Gas and Pipelines Ltd. (AGPL). Each division is operated by a separate management group, and each maintains its own books of account. ATCO Pipelines is engaged in the transmission of natural gas in the Province of Alberta. Its head office and registered office is at 4th floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4. ATCO Gas and Pipelines Ltd. is principally owned by CU Inc. which is controlled by Canadian Utilities Limited, which in turn is principally controlled by ATCO Ltd. and its controlling share owner, the Southern family.

In these financial statements, ATCO Pipelines is also referred to as "the Company".

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

Management authorized these financial statements for issue on April 29, 2022.

BASIS OF MEASUREMENT

The financial statements are prepared on a historic cost basis, except for retirement benefit obligations which are carried at remeasured amounts. ATCO Pipelines' significant accounting policies are described in Note 24.

FUNCTIONAL AND PRESENTATION CURRENCY

The financial statements are presented in Canadian dollars, which is ATCO Pipelines' functional currency.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, assumptions and estimates are described in Note 20.

ADOPTION OF NEW ACCOUNTING INTERPRETATION

In April 2021, the IFRS Interpretations Committee published a final agenda decision with respect to recognition of certain configuration and customization expenditures related to cloud computing with retrospective application. Costs that do not meet the capitalization criteria should be expensed as incurred. Any changes resulting from the decision were required to be implemented by December 31, 2021.

As a result of the review of the impact of the decision on the financial statements, ATCO Pipelines recorded a decrease to intangible assets of $0.3 million with a corresponding increase to other expenses in the statement of earnings (Note 10).

3. ADJUSTED EARNINGS

ADJUSTED EARNINGS

Adjusted earnings are earnings for the year after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of the Company,
- one-time gains and losses,
- impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings is a key measure used by the Chief Operating Decision Maker (CODM) to assess performance and allocate resources. Other accounts in the financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31, is shown below.

	2021	2020
Adjusted earnings	**81,078**	89,029
Early termination of the master service agreement for managed IT services	**(2,615)**	(3,996)
Restructuring costs	**(173)**	(701)
Rate-regulated activities	**(19,538)**	(27,805)
IT Common Matters decision	**(1,028)**	(1,415)
Dividends on equity preferred shares	**1,365**	1,556
Earnings for the year	**59,089**	56,668

Early termination of the master service agreement for managed IT services

On December 31, 2020, Canadian Utilities Limited, signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) to provide managed information technology (IT) services. These services were previously provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring December 2024. The transition of the managed IT services from Wipro to IBM commenced on February 1, 2021 and was completed at December 31, 2021.

On December 31, 2020, ATCO Pipelines recognized an onerous contract provision of $5.1 million ($4 million after-tax), which represents management's best estimate of the costs to exit the Wipro MSA. The provision is included in provisions and other current liabilities in the balance sheet and other expenses in the statement of earnings. The onerous contract provision is not in the normal course of business and has been excluded from Adjusted Earnings.

In addition, the Company recognized transition costs of $3.3 million ($2.6 million after-tax) in 2021. The transition costs related to activities to transfer the managed IT services from Wipro to IBM. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that ATCO Pipelines is eligible to adopt. In the absence of this guidance, ATCO Pipelines does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, ATCO Pipelines recognizes revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

ATCO Pipelines uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles (GAAP) to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of ATCO Pipelines' rate-regulated activities. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Revenues to be billed in future periods	Deferred income taxes.	ATCO Pipelines recognizes revenues associated with recoverable costs in advance of future billings to customers.	ATCO Pipelines recognizes costs when they are incurred, but does not recognize their recovery until changes to customer rates are made and collected through future billings.
2.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	ATCO Pipelines recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	ATCO Pipelines does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
3.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	ATCO Pipelines recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	ATCO Pipelines recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

The significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2021	2020
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**8,627**	5,404
Revenues to be billed in future periods		
Deferred income taxes (2)	**(22,934)**	(26,142)
Regulatory decisions received (see below)	**(266)**	(2,874)
Settlement of decisions and other items	**(4,965)**	(4,193)
	(19,538)	(27,805)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by ATCO Pipelines.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. The significant decision impacting adjusted earnings during 2021 is provided below:

Decision	Amount	Description
2021-23 GRA Compliance Decision	(1,461)	On June 16, 2020, ATCO Pipelines filed a GRA for 2021-2023. On June 24, 2021 the AUC issued a decision related to the 2021-2023 GRA resulting in a decrease in adjusted earnings of $1.5 million recorded in 2021.
2021 Pioneer Pipeline Placeholder Decision	1,726	On December 13, 2021 ATCO Pipelines filed an application to update the revenue requirement placeholder for the acquisition of the Pioneer Pipeline for the years of 2021-2023. On January 12, 2022, the AUC issued a decision resulting in an adjusted earnings of $1.7 million recorded in 2021.

The significant decisions impacting adjusted earnings during 2020 are provided below:

Decision	Amount	Description
2019-2020 General Rate Application	(2,874)	On July 30, 2018, ATCO Pipelines filed a GRA for 2019 and 2020. On September 21, 2020 the AUC issued its second compliance decision related to the 2019-2020 GRA resulting in an increase in adjusted earnings of $2.9 million recorded in 2020. Of this amount, $1.0 million relates to 2019.

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by CU Inc.'s parent, Canadian Utilities Limited, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2021 was $1.0 million (2020 - $1.4 million).

4. REVENUES

The Company disaggregates revenues based on the revenue streams. The disaggregation of revenues by revenue streams for the year ended December 31 is shown below:

	2021	2020
Transmission services	**308,136**	295,594
Customer contributions	**3,899**	3,821
Franchise fees	**5,147**	4,180
Other	**4,057**	12,026
	321,239	315,621

5. OTHER COSTS AND EXPENSES

In addition to rent, utilities, and goods and services such as professional fees, contractor costs, technology related expenses, advertising and other general and administrative expenses, other costs and expenses included costs related to the transition of managed information technology services of $3.3 million ($2.6 million after-tax) in 2021 (2020- $5.1 million) (see Note 3).

6. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2021	2020
Long-term debt	**57,404**	54,883
Other	**2,134**	1,699
	59,538	56,582
Less: interest capitalized *(Note 9)*	**(1,631)**	(3,889)
	57,907	52,693

Borrowing costs capitalized to property, plant and equipment during 2021 were calculated by applying a weighted average interest rate of 4.1 per cent to expenditures on qualifying assets (2020 - 4.3 per cent).

7. INCOME TAXES

INCOME TAX EXPENSE

ATCO Pipelines does not file an income tax return. Its divisional share of the income tax provision is calculated as if it was a legal entity.

The income tax rate for 2021 is 23.0 per cent (2020 - 24.0 per cent).

The components of income tax expense are summarized below.

	2021	2020
Current income tax expense		
Expenses for the year	**(5,280)**	(7,257)
Adjustment in respect of prior years	**(1,349)**	(1,057)
	(6,629)	(8,314)
Deferred income tax expense		
Reversal of temporary differences	**23,179**	23,418
Adjustment in respect of prior years	**1,654**	964
	24,833	24,382
	18,204	16,068

The reconciliation of statutory and effective income tax expense is as follows:

	2021		2020	
Earnings before income taxes	**77,292**	**%**	72,736	%
Income taxes, at statutory rates	**17,777**	**23.0**	17,457	24.0
Part VI.I tax net of transfer benefit	**106**	**0.1**	100	0.1
Other	**321**	**0.4**	(1,489)	(2.0)
	18,204	**23.5 %**	16,068	22.1 %

DEFERRED INCOME TAXES

The changes in deferred income tax liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Retirement Benefit Obligations	Other	Total
December 31, 2019	148,738	12,377	(3,344)	1,788	159,559
Charge (credit) to earnings	25,656	163	(90)	(1,347)	24,382
Credit to other comprehensive income	–	–	(318)	–	(318)
Other	–	–	–	(2)	(2)
December 31, 2020	174,394	12,540	(3,752)	439	183,621
Charge (credit) to earnings	**24,729**	**58**	**474**	**(428)**	**24,833**
Credit to other comprehensive income	**–**	**–**	**500**	**–**	**500**
December 31, 2021	**199,123**	**12,598**	**(2,778)**	**11**	**208,954**

ATCO Pipelines does not expect its deferred income tax liabilities to reverse within the next twelve months.

8. INVENTORIES

Inventories at December 31 are comprised of:

	2021	2020
Natural gas and fuel in storage	**6,876**	7,133
Raw materials and consumables	**79**	179
	6,955	7,312

For the year ended December 31, 2021, inventories recognized as an expense were $0.1 million (2020 - $0.1 million).

9. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost					
December 31, 2019	2,492,058	5,715	218,419	74,802	2,790,994
Additions	–	–	191,068	–	191,068
Transfers	345,016	–	(348,752)	3,736	–
Retirements and disposals	(13,275)	–	–	(2,847)	(16,122)
Transfer to affiliate	2,735	–	–	435	3,170
December 31, 2020	2,826,534	5,715	60,735	76,126	2,969,110
Additions	–	–	**351,177**	–	**351,177**
Transfers	**372,775**	**530**	**(379,853)**	**6,548**	–
Retirements and disposals	**(17,602)**	–	–	**(1,874)**	**(19,476)**
Transfer to affiliate	**(7,802)**	–	–	–	**(7,802)**
December 31, 2021	**3,173,905**	**6,245**	**32,059**	**80,800**	**3,293,009**
Accumulated depreciation					
December 31, 2019	629,725	–	–	29,436	659,161
Depreciation	65,592	–	–	5,426	71,018
Retirements and disposals	(13,275)	–	–	(2,847)	(16,122)
Transfer to affiliate	703	–	–	–	703
December 31, 2020	682,745	–	–	32,015	714,760
Depreciation	**71,509**	–	–	**5,561**	**77,070**
Retirements and disposals	**(17,602)**	–	–	**(1,874)**	**(19,476)**
Transfer to affiliate	**(2,079)**	–	–	–	**(2,079)**
December 31, 2021	**734,573**	–	–	**35,702**	**770,275**
Net book value					
December 31, 2020	2,143,789	5,715	60,735	44,111	2,254,350
December 31, 2021	**2,439,332**	**6,245**	**32,059**	**45,098**	**2,522,734**

The additions to property, plant and equipment included $1.4 million of interest capitalized during construction for the year ended December 31, 2021 (2020 - $3.6 million).

Pioneer natural gas pipeline acquisition

In 2020, the Company, entered into an agreement to acquire the Pioneer Pipeline from Tidewater Midstream & Infrastructure Ltd. and its partner TransAlta Corporation, subject to customary conditions including regulatory approvals by the Alberta Utilities Commission (AUC) and Canada Energy Regulator.

The 131 km natural gas pipeline runs from the Drayton Valley area to the Wabamum area west of Edmonton. On June 15, 2021, the AUC issued a decision approving the acquisition of the Pioneer Pipeline and associated costs, totaling $265 million.

Consistent with the geographic areas defined in the Integration Agreement, the Company will transfer to Nova Gas Transmission Ltd. (NGTL) the 30 km segment of pipeline that is located in the NGTL footprint for approximately $65 million.

The transaction to acquire the Pioneer Pipeline closed in 2021. The transfer to NGTL received approval from the Canada Energy Regulator on December 22, 2021. As a result, $197 million was recorded in additions to property, plant and equipment in the balance sheet and the statement of cash flows. The costs incurred for the segment of the pipeline that will be sold to NGTL, amounting to $64 million, were recorded as assets held-for-sale in prepaid expenses and other current assets in the balance sheet, and were included in other investing activities in the statement of cash flows. Pipeline integration costs of $1 million are expected to be incurred in the first half of 2022, which would result in total costs of $262 million, $3 million less than the approved amount of $265 million.

The transfer to NGTL occurred in the first quarter of 2022 for $63 million, not including $1 million of capital upgrades that will be settled in the first half of 2022, which remain as assets held-for-sale on the balance sheet.

The Company applied the optional IFRS 3 *Business combinations* concentration test to the acquisition of the Pioneer Pipeline, which has resulted in the acquired asset being accounted for as an asset acquisition.

10. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Work-in-progress	Other	Total
Cost					
December 31, 2019	23,294	115,713	9,547	3,688	152,242
Additions	–	–	13,199	–	13,199
Transfers	3,730	9,719	(13,451)	2	–
Retirements	(1,971)	(6)	–	–	(1,977)
December 31, 2020	25,053	125,426	9,295	3,690	163,464
Additions	**–**	**–**	**12,132**	**–**	**12,132**
Transfers	**4,859**	**12,807**	**(17,664)**	**(2)**	**–**
Retirements	**(1,337)**	**(111)**	**–**	**–**	**(1,448)**
December 31, 2021	**28,575**	**138,122**	**3,763**	**3,688**	**174,148**
Accumulated amortization					
December 31, 2019	8,496	15,859	–	1,948	26,303
Amortization	3,041	1,536	–	78	4,655
Retirements	(1,971)	(36)	–	–	(2,007)
December 31, 2020	9,566	17,359	–	2,026	28,951
Amortization	**3,259**	**1,659**	**–**	**78**	**4,996**
Retirements	**(1,020)**	**(34)**	**–**	**–**	**(1,054)**
December 31, 2021	**11,805**	**18,984**	**–**	**2,104**	**32,893**
Net book value					
December 31, 2020	15,487	108,067	9,295	1,664	134,513
December 31, 2021	**16,770**	**119,138**	**3,763**	**1,584**	**141,255**

The additions to intangibles included $0.2 million of interest capitalized during construction for year ended December 31, 2021 (2020 - $0.3 million)

In 2021, ATCO Pipelines recorded a decrease to intangibles of $0.3 million with a corresponding increase to other expenses in the statement of earnings as a result of the review of the impacts of IFRIC on recognition of certain configuration and customization expenditures related to cloud computing costs (Note 2).

11. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2021	2020
Debentures - unsecured	4.137% (2020 - 4.309%)	**1,530,468**	1,349,468
(interest is the average effective interest rate weighted by principal amounts outstanding)			
Less: deferred financing charges		**(8,877)**	(7,675)
		1,521,591	1,341,793
Less: amounts due within one year		**(13,197)**	(39,000)
		1,508,394	1,302,793

Debenture issuances and repayments

In 2021, ATCO Pipelines issued $220.0 million of 3.174 per cent debentures maturing on September 5, 2051. In 2021, ATCO Pipelines also repaid $39.0 million of 4.801 per cent debentures.

In 2020, ATCO Pipelines issued $85.0 million of 2.609 per cent debentures maturing on September 28, 2050. In 2020, ATCO Pipelines also repaid $11.3 million of 11.770 per cent debentures.

12. RETIREMENT BENEFITS

ATCO Pipelines, together with Canadian Utilities Limited and its subsidiary companies, maintains registered defined benefit and defined contribution pension plans for most of its employees and non-registered non-funded defined benefit pension plans for certain officers and key employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

Information about the plans as a whole, in aggregate, can be found in the Canadian Utilities Limited consolidated financial statements for the year ended December 31, 2021.

THE COMPANY'S BENEFIT PLANS

Information about the ATCO Pipelines' participation in the group benefit plans is as follows:

		2021		2020
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Defined benefit plans cost	**1,531**	**429**	2,204	430
Defined contribution plans cost	**1,927**	**–**	1,904	–
Total cost	**3,458**	**429**	4,108	430
Less: Capitalized	**1,715**	**257**	2,259	237
Net cost recognized	**1,743**	**172**	1,849	193
Accrued benefit obligations				
Beginning of year	7,301	10,361	6,425	9,389
Defined benefit plan cost	**1,531**	**429**	2,204	430
Benefit payments	**(648)**	**(263)**	(645)	(336)
Contributions to defined benefit plans	**(932)**	**–**	(1,185)	–
Actuarial (gains) losses	**(1,069)**	**(1,111)**	502	878
End of year	**6,183**	**9,416**	7,301	10,361

Weighted average assumptions

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Average compensation increase for the year	**2.25 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.16 %**	**3.16 %**	2.58 %	2.58 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.05 %**	n/a	5.11 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) The Company uses a graded drug cost trend rate, which assumes a 5.05 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

Defined benefit plan funding

An actuarial valuation for funding purposes as of December 31, 2020 was completed in 2021 for the registered defined benefit pension plans. The estimated contribution for 2022 is $0.9 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2023.

13. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of trade accounts receivable and contract assets, trade accounts receivable from parent and affiliate companies and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, trade accounts receivable and contract assets are included in accounts receivable and contract assets:

	2021	2020
Trade accounts receivable and contract assets	**27,845**	24,441
Other accounts receivable	**791**	809
	28,636	25,250

At December 31, trade accounts receivable from parent and affiliate companies are included in accounts receivable from parent and affiliate companies:

	2021	2020
Trade accounts receivable from parent and affiliate companies	**6,815**	6,010

The significant changes in trade accounts receivable and contract assets are as follows:

December 31, 2019	26,135
Revenue from satisfied performance obligations	303,260
Payments received	(304,954)
December 31, 2020	24,441
Revenue from satisfied performance obligations	**315,221**
Payments received	**(311,817)**
December 31, 2021	**27,845**

CUSTOMER CONTRIBUTIONS

Certain additions to property, plant and equipment are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of natural gas, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Changes in customer contributions balance are summarized below.

	2021	2020
Beginning of year	152,662	145,379
Receipt of customer contributions	**10,179**	11,104
Amortization	**(3,899)**	(3,821)
End of year	**158,942**	152,662

14. EQUITY PREFERRED SHARES

EQUITY PREFERRED SHARES TO CU INC.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2021		2020
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**800,000**	**20,000**	800,000	20,000
2.292% Series 4 (1)	**180,000**	**4,500**	180,000	4,500
Issuance costs		**(406)**		(406)
		24,094		24,094

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.243 per cent.

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.14325	1.36 %	June 1, 2026 (4)	Series 5 (5)

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by ATCO Pipelines or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

EQUITY PREFERRED SHARES TO CANADIAN UTILITIES LIMITED

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

		2021		2020
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	–	–	465,578	11,640
Issuance costs		–		(8)
		–		11,632

In 2021, ATCO Pipelines redeemed all of the issued 4.60 per cent Series V Preferred Shares for $11.6 million plus accrued dividends.

Rights and Privileges

The Series V Perpetual Cumulative Second Preferred Shares are redeemable at the option of ATCO Pipelines at anytime, at the stated value plus accrued and unpaid dividends.

DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	2021	2020
Cumulative Redeemable Preferred Shares		
4.60% Series 1	**1.1500**	1.1500
2.292% Series 4 (1)	**0.5669**	0.5608
Perpetual Cumulative Second Preferred Shares		
4.60% Series V (2)	**0.8625**	1.1500

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.24 per cent.

(2) The 4.60% Series V Preferred Shares were redeemed on August 27, 2021.

The payment of dividends is at the discretion of the Board and depends on the financial condition of ATCO Pipelines and other factors.

On January 20, 2022, ATCO Pipelines declared first quarter eligible dividends of $0.28750 per Series 1 Preferred Share and $0.14325 per Series 4 Preferred Share.

15. CLASS A AND CLASS B SHARES

The number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31 is shown below.

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2021 and 2020	**1,448,849**	**42,315**	**908,720**	**32,911**	**2,357,569**	**75,226**

Class A and B shares have no par value.

The Company declared and paid cash dividends of nil per Class A non-voting share and Class B common share during 2021 (2020 - $10.94). The payment and amount of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

16. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	2021	2020
Depreciation and amortization	**81,086**	74,728
Income taxes expense	**18,204**	16,068
Contributions by customers for extensions to plant	**10,179**	11,104
Amortization of customer contributions	**(3,899)**	(3,821)
Net finance costs	**57,907**	52,678
Income taxes recovered	**8,725**	10,647
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**–**	5,191
Other	**(883)**	(803)
	171,319	165,792

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2021	2020
Operating activities		
Accounts receivable and contract assets	**(3,367)**	3,971
Accounts receivable from parent and affiliate companies	**(805)**	1,828
Inventories	**357**	(25)
Prepaid expenses and other current assets	**582**	(995)
Accounts payable and accrued liabilities	**2,223**	(5,537)
Accounts payable to parent and affiliate companies	**2,064**	(1,169)
Provision and other current liabilities	**(254)**	(2)
	800	(1,929)
Investing activities		
Accounts receivable and contract assets	**(19)**	(350)
Accounts payable and accrued liabilities	**(9,799)**	187
	(9,818)	(163)

CASH POSITION

Cash position in the statement of cash flows at December 31 is comprised of:

	2021	2020
Cash	**437**	–
Short-term advances to parent company *(Note 23)*	**52,000**	–
Cash and cash equivalents	**52,437**	–
Bank indebtedness	**–**	(581)
Short-term advances from parent company *(Note 23)*	**(145,704)**	(6,000)
	(93,267)	(6,581)

17. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash, short-term advances to parent company, accounts receivable and contract assets, accounts receivable from parent and affiliate companies, bank indebtedness, short-term advances from parent company, accounts payable and accrued liabilities and accounts payable to parent and affiliate companies.	Assumed to approximate carrying value due to their short-term nature.
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the ATCO Pipelines' current borrowing rate for similar borrowing arrangements (Level 2).

The fair values of the Company's financial instruments measured at amortized cost at December 31 are as follows:

		2021		2020	
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Liabilities					
Long-term debt	11	**1,521,591**	**1,710,282**	1,341,793	1,653,209

18. RISK MANAGEMENT

ATCO Pipelines is exposed to a variety of risks associated with the use of financial instruments: credit risk and liquidity risk. Its Board is responsible for understanding the principal risks of ATCO Pipelines' business, achieving a proper balance between risks incurred and the potential return to share owner, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of ATCO Pipelines. The Board reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect ATCO Pipelines' ability to achieve its strategic or operational targets. The Board is also responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparty's inability to discharge their contractual obligations to ATCO Pipelines. It is exposed to credit risk on its cash, accounts receivable and contract assets, and accounts receivable from parent and affiliate companies. The exposure to credit risk represents the total carrying amount of these financial instruments in the balance sheet.

ATCO Pipelines has a concentration of credit risk with a single counterparty. This risk is minimized as the counterparty is NOVA Gas Transmission Ltd., a subsidiary of TC Energy, which is a large, credit-worthy counterparty.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days, where the Company believes there is a high probability of a customer default, additional credit allowances are recorded. At December 31, 2021 and 2020, the expected credit loss allowance was less than $1.0 million. No other impairments have been identified within accounts receivable or contract assets.

LIQUIDITY RISK

Liquidity risk is the risk that ATCO Pipelines will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from ATCO Pipelines' general funding needs and in the management of its assets, liabilities and capital structure. Cash flow from operations provides a substantial portion of ATCO Pipelines' cash requirements. Additional cash requirements are met with the use of existing cash balances, obtaining advances from the parent company and issuance of long-term debt and Class A and B shares. Short term advances from the parent company provide flexibility in the timing and amounts of long term financing.

Line of credit

ATCO Pipelines has a line of credit available of $5.0 million (2020 - $5.0 million). The credit line enables it to obtain financing for general business purposes. At December 31, 2021 and 2020, no amounts were used under the line of credit.

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities at December 31, 2021, of ATCO Pipelines' financial liabilities based on the contractual undiscounted cash flows.

	2022	2023	2024	2025	2026	2027 and thereafter
Short-term advances from parent company	145,704					
Accounts payable and accrued liabilities	25,180	–	–	–	–	–
Accounts payable to parent and affiliate companies	20,557	–	–	–	–	–
Long-term debt:						
Principal	13,197	16,371	4,000	–	–	1,496,900
Interest expense	59,453	58,098	57,384	57,339	57,339	1,095,117
	264,091	74,469	61,384	57,339	57,339	2,592,017

The table below analyzes the remaining contractual maturities at December 31, 2020, of ATCO Pipelines' financial liabilities based on the contractual undiscounted cash flows.

	2021	2022	2023	2024	2025	2026 and thereafter
Bank indebtedness	581	–	–	–	–	–
Short-term advances from parent company	6,000					
Accounts payable and accrued liabilities	32,756	–	–	–	–	–
Accounts payable to parent and affiliate companies	16,359	–	–	–	–	–
Long-term debt:						
Principal	39,000	13,197	16,371	4,000	–	1,276,900
Interest expense	55,125	52,470	51,115	50,401	53,033	970,331
	149,821	65,667	67,486	54,401	53,033	2,247,231

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact ATCO Pipelines by causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the operations of ATCO Pipelines.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the business of ATCO Pipelines.

While the investments of ATCO Pipelines are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on ATCO Pipelines remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, ATCO Pipelines has been following recommendations by local and federal public health authorities to adjust operational requirements as needed to ensure a coordinated approach across operations of ATCO Pipelines. As a result of these efforts and the experience in crisis response, the operations, financial position and performance of ATCO Pipelines have not been significantly impacted for the year ended December 31, 2021.

CLIMATE CHANGE RISK

ATCO Pipelines manages climate risks related to assets, including preparing for, and responding to, extreme weather events through activities such as proactive route and site selection, asset hardening, regular maintenance, and insurance. ATCO Pipelines follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital expenditures or acquiring assets, ATCO Pipelines considers site specific climate and weather factors, such as flood plain mapping and extreme weather history.

ATCO Pipelines also continues to explore and implement opportunities in energy efficiency. This process is associated with risks and uncertainties, and is highly dependent on changes in legislation, market price volatility, local and global demand on energy, as well as the timing of when the local and global markets transition to a more energy efficient and cleaner fuels-based economy. The extent and significance of the future impact of such risks and uncertainties remain unknown.

19. CAPITAL DISCLOSURES

ATCO Pipelines' objective when managing capital is to remain within the capital structure approved by the AUC, which, through the generic cost of capital decisions established the capital structure for ATCO Pipelines. In October 2020, ATCO Pipelines received the 2021 Generic Cost of Capital decision. The decision established a common equity ratio of 37.0 per cent for 2021, consistent to what was previously approved.

ATCO Pipelines includes share owner’s equity, preferred shares, and long term debt, as adjusted in accordance with the Financial Accounting Standards Board (FASB) standards (see Note 3 and 24), in its determination of capitalization. In maintaining or adjusting its capital structure, ATCO Pipelines may adjust the dividends paid to the share owner, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, and long-term debt.

20. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in ATCO Pipelines’ overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. ATCO Pipelines continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made in order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

ATCO Pipelines makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Income taxes

ATCO Pipelines makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, and the potential for technological obsolescence.

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. ATCO Pipelines makes judgments in making these assumptions and selecting the inputs to the impairment calculation based on the Company past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Impairment of long-lived assets

ATCO Pipelines continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, ATCO Pipelines estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Leases

Useful lives of right-of-use assets are based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, ATCO Pipelines identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

Retirement benefits

ATCO Pipelines, together with Canadian Utilities Limited and its subsidiary companies, consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 12.

Asset retirement obligations

ATCO Pipelines estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

Use of judgments and estimates around the COVID-19 pandemic

For the year ended December 31, 2021, ATCO Pipelines performed an assessment of the impacts of uncertainties around the COVID-19 pandemic on its financial position, financial performance and cash flows. The assessment required use of judgments and estimates and resulted in no material impacts to the financial statements.

21. CONTINGENCIES

ATCO Pipelines is party to a number of disputes and lawsuits in the normal course of business. ATCO Pipelines believes that the ultimate liability arising from these matters will have no material impact on the financial statements.

22. COMMITMENTS

In addition to commitments disclosed elsewhere in the financial statements,ATCO Pipelines has entered into a number of agreements realting to operating and maintenance, information technology services and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2022	**2023**	**2024**	**2025 and thereafter**
Purchase obligations:				
Operating and maintenance agreements	970	–	–	–
Information technology services	1,456	1,443	1,372	457
Capital expenditures	19,045	–	–	–
	21,471	1,443	1,372	457

23. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH RELATED PARTIES

During the year, ATCO Pipelines entered into the following transactions with related parties:

Entity	Relationship	Transaction	Recorded As	2021	2020
ATCO Ltd. / CUL / CU Inc.	Parent	Interest on long-term advances	Interest Expense	**59,499**	55,622
		Administrative services, rent and aircraft	Other expenses	**11,391**	9,853
		Administrative services, rent and aircraft	Property, plant and equipment	**2,263**	2,573
		Administrative services, rent and aircraft	Revenues	**3**	–
		Licensing fees	Other expenses	**1,199**	897
ATCO Gas	Division of AGPL	Engineering services, mechanical services, communications operations, office services, operations	Plant and equipment maintenance	**3,654**	2,667
		Contract services, net of asset transfers	Revenues	**1,160**	3,004
		Engineering and construction services	Property, plant and equipment	**11,561**	13,895
		Transfer of assets	Property, plant and equipment	**5,799**	2,062
		Transfer of assets	Deferred revenue	**2,486**	–
ATCO Electric	Affiliate	Contract services	Plant and equipment maintenance	**19**	–
		Contract services	Property, plant and equipment	**298**	87
ATCO Energy Solutions Ltd.	Affiliate	Contract services	Revenues	**971**	6,162
		Salt cavern gas purchase	Other expenses	**25**	25
		Transfer of assets	Property, plant and equipment	**–**	436
ATCO Power (2010)	Affiliate	Contract services	Revenues	**174**	122
ATCO Pipelines S.A. de C.V.	Affiliate	Contract services	Revenues	**172**	218
IEIE S.A. de C.V.	Affiliate	Contract services	Revenues	**202**	188
ATCO Energy Ltd	Affiliate	Contract services	Other expenses		1
		Distribution service costs	Other expenses	**464**	411
ATCO Infrastructure Solutions Ltd.	Affiliate	Contract services	Revenues	**94**	43
ATCO Investments Ltd.	Affiliate	Rent	Other expenses	**69**	69

Affiliate companies are subsidiaries of ATCO Pipeline’s parent or ultimate parent.

ATCO Pipelines incurred $0.1 million (2020 - $0.1 million) in advertising and promotion expenses from an entity related through common control.

These transactions are in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

RELATED PARTY LOANS AND BALANCES

Balances	Recorded As	2021	2020
Receivables from related parties [(1)]	Accounts receivable from parent and affiliate companies	**6,815**	6,010
Short-term advances [(2)]	Short-term advances from parent company	**145,704**	6,000
Payables to related parties [(1)]	Accounts payable to parent and affiliate companies	**20,557**	16,359
Long-term advances *(Note 11)*	Long-term debt	**1,521,591**	1,341,793
Equity preferred shares *(Note 14)*	Equity preferred shares to parent company	**24,094**	35,726

(1) Generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

(2) Short-term advances are obtained in the normal course of business and are generally due within 30 days or less from the date of the transaction. The interest rates are based on the Bank of Canada overnight rate plus an applicable spread.

24. ACCOUNTING POLICIES

RATE REGULATION

Nature and economic effects of rate regulation

ATCO Pipelines is regulated by the Alberta Utilities Commission ("AUC") and is subject to a cost of service regulatory mechanism under which the regulator establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for ATCO Pipelines is the aggregate of the regulator approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. ATCO Pipelines earns a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base based on the historical and forecast weighted average cost of the ATCO Pipelines' debt and preferred shares and establishes the capital structure for ATCO Pipelines.

Under the cost of service methodology, ATCO Pipelines seeks approval for its revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to the AUC's approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

In the absence of a rate-regulated standard under IFRS that ATCO Pipelines is eligible to adopt, ATCO Pipelines does not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, ATCO Pipelines records revenues in earnings when amounts are billed to customers consistent with the rate design approved by the AUC (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, ATCO Pipelines recognizes revenue equal to what it has the right to invoice.

Where ATCO Pipelines arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from ATCO Pipelines' customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Natural gas transmission

Revenue from natural gas transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission prices. The recovery is part of the provision of continuous natural gas transmission service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when ATCO Pipelines can no longer withdraw the offer of those benefits and when it recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in other comprehensive income (OCI) or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which ATCO Pipelines operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

CASH

Cash consists of cash at bank less outstanding cheques.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, and contracted services. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to ATCO Pipelines and the cost can be measured reliably.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

ATCO Pipelines allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Gas transmission equipment	3 to 57 years	42 years	2.4 %
Other plant, equipment and machinery	4 to 31 years	14 years	7.1 %

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. ATCO Pipelines amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and not longer than 80 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the statements of earnings.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

PROVISIONS

ATCO Pipelines recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event,

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of ATCO Pipelines. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, included in other liabilities, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

ATCO Pipelines classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on ATCO Pipelines' business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. ATCO Pipelines' long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if ATCO Pipelines intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) ATCO Pipelines has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

ATCO Pipelines uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

ATCO Pipelines applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by ATCO Pipelines and recognizing the disposal of an asset on the day it is delivered by ATCO Pipelines. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, ATCO Pipelines assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

ATCO Pipelines applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets, ATCO Pipelines estimates credit loss allowances at initial recognition and throughout the life of the receivable.

RETIREMENT BENEFITS

ATCO Pipelines participates, together with Canadian Utilities Limited and its subsidiary companies, in a registered group defined benefit pension plan (the Group Plan). The assets of the registered defined benefit plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, ATCO Pipelines is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. Contributions related to current service cost are allocated in proportion to capped pensionable earnings for each company. Contributions related to the amortization of the unfunded liability are allocated in proportion to the corresponding going-concern liability for each company which was established based on the actuarial valuations for funding purposes as of December 31, 2020.

The minimum funding requirements for the Group Plan are comprised of the contributions related to current service cost and the amortization of the unfunded liability as determined by the actuary. ATCO Pipelines does not have any liability to the Group Plan other than its minimum funding requirements. In the event of a withdrawal from the Group Plan or the termination of the Group Plan, the companies will still be required to contribute to the Group Plan where such contributions are required under pension regulations.

ATCO Pipelines participates, together with Canadian Utilities Limited and its subsidiary companies, in OPEB and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and ATCO Pipelines accrues for its obligations under these plans. Costs of these benefits are determined using the projected unit credit method and reflect management's best estimates of wage and salary increases, age at retirement and expected health care costs. ATCO Pipelines, together with Canadian Utilities Limited and its subsidiary companies, consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period.

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

For the non-registered defined benefit pension plans, ATCO Pipelines is assessed a percentage of the total cost of the plans.

For the non-registered defined benefit pension plan and the OPEB plans, gains and losses resulting from changes in assumptions, including the liability discount rate and future compensation rates, used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For non-registered defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of retirement benefits for registered defined benefit pension plans and defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2021, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

Énergir Annual Information Form, Fiscal year ended September 30, 2022

ÉNERGIR INC.

ANNUAL INFORMATION FORM

Fiscal year ended on September 30, 2022

December 15, 2022

TABLE OF CONTENTS

Documents incorporated by reference

As of the date hereof, sections of the Management's Discussion and Analysis of Énergir Inc. dated November 22, 2022 for the fiscal year ended on September 30, 2022 and the audited consolidated financial statements of Énergir Inc. for the fiscal years ended on September 30, 2022 and 2021, as detailed below, are specifically incorporated by reference into and form an integral part of this Annual Information Form. These documents may be downloaded from the SEDAR website at www.sedar.com.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

To help investors better understand the future outlook of Énergir Inc. and Énergir, L.P. (as these two terms are defined in the Glossary of Terms) and thereby make more informed investment decisions, certain statements in this Annual Information Form may be forward looking, in particular statements that describe actions, activities, events, results or developments that Énergir Inc. or Énergir, L.P. expects or anticipates will or may occur in the future as well as other statements that are not historical facts. Such forward-looking information reflects the intentions, plans, expectations and opinions of Management (as such term is defined in the Glossary of Terms) regarding the future growth, operating results, performance and business prospects and opportunities of Énergir Inc. or Énergir, L.P. Forward-looking statements are often identified by words and expressions such as "plans," "expects," "is expected," "budgeted," "scheduled," "estimated," "seeks," "aims," "forecasts," "intends," "anticipates," or "believes" or by statements that certain actions, events or results "may," "could," "would," "might" or "will" be taken, occur, or be achieved, and other variants and similar expressions, as well as the negative or conjugated forms, as they relate to Énergir Inc. or Énergir, L.P. The forward-looking statements in this Annual Information Form include, among other things, statements on (i) the general development of the business; (ii) growth or profitability outlooks; (iii) certain decisions by regulatory agencies, as well as the terms and timing of those decisions; (iv) the competitive position, including the impact of fluctuating global oil prices; (v) Quebec's 2030 Energy Policy, the Montréal Climate Plan and Vermont's Renewable Energy Standard, and the implementation thereof as well as the positioning of Énergir, L.P. and its subsidiaries in relation thereto; (vi) the distribution of RNG in Énergir, L.P.'s networks; (vii) the impact of climate change on Énergir, L.P. and its material subsidiary, Green Mountain (as such term is defined in the Glossary) (collectively, the "**Corporations**"); the Corporations' decarbonization strategy in order to mitigate the risks of climate change and to adapt to such changes and take advantage of opportunities as well as other information such as: quantitative scenarios issued by organizations forecasting several possible global GHG emission pathways by 2030-2050 and which the Corporations have relied on, scenarios that take into account the impact, over different timelines, of what the climate risks and opportunities identified in this Annual Information Form might have on the resilience of the Corporations' business models (collectively, the "**Scenarios**"); the scenarios of Énergir, L.P. and Green Mountain, as they have been scaled for Quebec and Vermont; Énergir, L.P.'s Vision 2030-2050 (as such term is defined in the Glossary); Green Mountain's climate plan; and the Corporations' risk management processes and opportunities related to climate change; (viii) the liquidity position and financing capability of Énergir Inc. and Énergir, L.P., (ix) new energy development and network development projects, (x) Énergir, L.P.'s anticipated distribution payments; (xi) the repercussions of the war in Ukraine; and (xii) the impact of COVID-19 and its variants, evolution, scope and duration on Énergir Inc. and Énergir, L.P. Such forward-looking statements reflect the current opinions of Management and are based on information currently available to it.

Forward-looking statements involve known and unknown risks and uncertainties and other factors outside the control of Management. A number of factors could cause the actual results of Énergir Inc. and Énergir, L.P. to differ significantly from historical results or current expectations, as described in the forward-looking statements, including but not limited to the general nature of the aforementioned: the terms of decisions rendered by regulatory agencies, uncertainty that approvals will be obtained by Énergir, L.P. from regulatory agencies and interested parties to carry out all of its activities and the socio-economic risks associated with such activities, the competitiveness of natural gas in relation to other energy sources in a context of fluctuating global oil prices, climate changes and their repercussions on the conduct of Énergir, L.P.'s activities (whether these result from severe or chronic physical elements or from political, regulatory, technological changes, including the evolving risk of cyberattacks and theft of identity or personal information, as well as legislative and market changes), uncertainty associated with the transition to a low-carbon economy and the implementation of Quebec's 2030 Energy Policy and Vermont's Renewable Energy Standard, the reliability or costs of natural gas and electricity supply, the integrity of the natural gas and electricity transportation and distribution systems, the evolution and profitability of development projects, the ability to complete attractive acquisitions and the related financing and integration aspects, the ability to complete new development projects, the ability to secure future financing, the availability and cost of labour as well as Énergir, L.P.'s ability to recruit and retain key resources, general economic conditions, the impact of inflation, interest and exchange rate fluctuations, the repercussions of an epidemic or pandemic outbreak (such as COVID-19) or other public health crisis, a potential U.S. or Canadian tax reform, the impact of a war or other geopolitical conflicts and other factors described under Item 10.2.6 *Risk Factors relating to Énergir Inc. and Énergir, L.P.* of this Annual Information Form (which are incorporated by reference from the Énergir Inc. Management's Discussion and Analysis for the fiscal year ended on September 30, 2022) and in subsequent Énergir Inc. quarterly Management's Discussion and Analysis that could report on changes in these risk factors. Although the forward-looking statements contained herein are based on what management believes to be reasonable assumptions, Management cannot assure investors that actual results will be consistent with these forward-looking statements. Assumptions underlying the forward-looking statements contained in this Annual Information Form include, among others, the assumptions that no unforeseen changes in the legislative and regulatory framework of energy markets in Quebec and in the United States will occur, that the applications filed with the various regulatory agencies will be approved as submitted, that natural gas prices will remain competitive, that the supply of natural gas and electricity will be maintained or will be available at competitive costs, that no significant event will occur outside the ordinary course of business, such as a calamity (including any that might result from the impact of climate change), a major service interruption or a cyberattack, that Énergir, L.P. can continue to distribute substantially all of its adjusted net income, that Énergir Inc. will be able to present its information in accordance with U.S. GAAP beyond 2023 or, after 2023, will adopt International Financial Reporting Standards that permit the recognition of regulatory assets and liabilities, that the liquidity needs for Énergir, L.P.'s development projects will be obtained through a combination of operating cash flows, borrowings on credit facilities, capital injections from Énergir, L.P.'s partners and issuance of debt securities, and that the subsidiaries will obtain the required authorizations and funds needed to finance their development projects, in addition to the other assumptions described in this Annual Information Form. These forward-looking statements are made as of the date of this Annual Information Form, and Management assumes no obligation to update or revise them to reflect new events or circumstances, except as required under applicable securities laws. These statements do not reflect the potential impact of any unusual item or any business combination or other transaction that may be announced or that may occur after the date hereof. All forward-looking statements in this Annual Information Form are qualified by these cautionary statements. Readers are cautioned not to place undue reliance on these forward-looking statements.

Measurement Conversion

The data used in this Annual Information Form are stated in metric units. Metric unit equivalents in the imperial system, including their respective abbreviations, are:

Metric Units	Approximate Imperial Equivalent
Thousand cubic metres (10^3m^3)	35.31 thousand cubic feet (Mcf)
Million cubic metres (10^6m^3)	35.31 million cubic feet (MMcf)
Billion cubic metres (10^9m^3)	35.31 billion cubic feet (Bcf)
Gigajoule (Gj)	0.95 million BTUs (MMBTU)
Kilometre (km)	0.62 mile

Unless otherwise indicated, the term “dollars” means Canadian dollars in this Annual Information Form. If foreign currencies are translated into Canadian dollars, the foreign exchange rate used is the rate at the date of the event to which reference is made.

Unless otherwise indicated, the information in this Annual Information Form is as of September 30, 2022.

GLOSSARY OF TERMS

In this Annual Information Form:

2022 Financial Statements means the audited consolidated financial statements of Énergir Inc. for the fiscal years ended on September 30, 2022 and 2021 and the notes and external auditor's report related thereto.

2022 MD&A means the Management's Discussion and Analysis of Énergir Inc. for the fiscal year ended on September 30, 2022 dated November 22, 2022 and filed with the Canadian Securities Administrators.

Affiliates has the meaning assigned to such expression in the *Securities Act* (Quebec).

Audit Committee means the Audit Committee established by the Board.

Beaupré Éole means Beaupré Éole GP.

Beaupré Éole 4 means Beaupré Éole 4 GP.

Board means the board of directors of Énergir Inc., in its capacity as general partner of Énergir, L.P.

Boralex means Boralex Inc.

°C means degrees Celsius.

Carbon neutrality or carbon neutral[(1)] means a net GHG emissions balance of zero. A business can achieve carbon neutrality by first avoiding and reducing its GHG emissions, and then by offsetting those emissions that could not be avoided or reduced by carbon sequestration or compensation (e.g. planting trees), therefore by producing negative emissions or being credited for the emission reductions or negative emissions produced by third parties. A carbon neutral business may therefore emit residual GHGs.

CATS means the cap-and-trade system for greenhouse gas emission allowances established by the *Regulation respecting the cap-and-trade system for greenhouse gas emission allowances* (Quebec).

CDPQ means the Caisse de dépôt et placement du Québec.

CER means the Canada Energy Regulator (formerly the National Energy Board).

CGC means the Compensation and Governance Committee established by the Green Mountain Board.

CGEE Committee means the Corporate Governance, Ethics and Environment Committee established by the Board on October 18, 2022.

CNG means compressed natural gas.

CO_2 eq. means carbon dioxide (CO_2) equivalent.

Commercial Market means primarily commercial establishments, institutions and multiple occupancy rental units, and small and medium-size businesses.

COVID-19 means the global coronavirus disease pandemic that broke out in 2020 and continued throughout fiscal year 2022.

CVPS means Central Vermont Public Service Corporation before the Merger.

Delayed Action Scenario means the 2°C or less by 2100 scenario compared to preindustrial levels by delayed action published by the Bank of Canada.

DBRS means DBRS Limited.

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(1) The definition used is adapted from the report entitled *Trajectoires de réduction d'emissions de GES du Québec - Horizons 2030 et 2050* (Quebec's GHG emission reduction pathways - 2030 and 2050 horizons, updated in 2021). Dunsky (page 6): https://www.dunsky.com/wp-content/uploads/2021/09/Rapport_Final_Trajectoires_QC_2021.pdf

Enbridge means Enbridge Inc.

Enbridge Gas means Enbridge Gas Inc., a corporation resulting from the merger between Union Gas Limited and Enbridge Gas Distribution Inc.

Énergir Development means Énergir Development Inc., formerly known as Valener Inc.

Énergir Inc. means Énergir Inc., formerly known as Gaz Métro Inc.

Énergir, L.P. means Énergir, L.P., formerly known as Gaz Métro Limited Partnership.

Énergir Management means Énergir Management L.P., formerly known as Gaz Métro Plus Limited Partnership.

ESG pertains to environmental, social and governance factors.

FERC means the United States Federal Energy Regulatory Commission.

Form 51-102F6 means Form 51-102F6 of *Regulation 51-102 respecting Continuous Disclosure Obligations*.

GAAP means generally accepted accounting principles.

Gaz Métro Éole means Gaz Métro Éole Inc.

Gaz Métro Éole 4 means Gaz Métro Éole 4 Inc.

Gaz Métro LNG means Gaz Métro LNG 2013, L.P. or Gaz Métro LNG, L.P., depending on the context.

GHG means greenhouse gases.

Green Mountain means Green Mountain Power Corporation, the corporation resulting from the Merger.

Green Mountain Board means the Board of Directors of Green Mountain.

HR-CG Committee means the Human Resources and Corporate Governance Committee established by the Board that was in existence in fiscal year 2022 up to October 18, 2022.

HR-SR Committee means the Human Resources and Social Responsibility Committee established by the Board on October 18, 2022.

Industrial Market means primarily large industrial businesses.

Interest, as the case may be, in a Non-regulated Energy Activity or a Permitted Economic Activity means (i) an investment therein by way of ownership of assets, securities or loans, and (ii) the indebtedness of a person other than Énergir, L.P. in respect thereof for which Énergir, L.P. is liable.

Intragas means collectively Intragas Inc.; Intragas Holding, Limited Partnership; Intragas Exploration, Limited Partnership; Intragas, Limited Partnership and their respective subsidiaries.

KPMG means KPMG LLP.

Limited Partnership Agreement means the Énergir, L.P. Limited Partnership Agreement amended and restated on December 5, 2019, as more fully described under 1.2.3 *Key Elements of the Limited Partnership Agreement*.

LNG means liquefied natural gas.

LSR Plant means the natural gas liquefaction, storage and regasification plant of Énergir, L.P. located in Montréal, Quebec.

Management means the management of Énergir Inc., in its capacity as general partner of Énergir, L.P.

Ministry of Environment means the department responsible for the environment in Quebec.

Merger means the October 1, 2012 merger of CVPS with Green Mountain Power Corporation, as it existed before October 1, 2012.

MW means megawatts.

Named Executive Officers has the meaning given to that term in Item 10.1.1 *Explanatory Note on Named Executive Officer Compensation Disclosure*.

NATEM means the North American TIMES Energy Model*.*

NDC means nationally determined contributions as part of the Paris Agreement.

NDC Scenario means the NDC Scenario, as described in greater detail in Item 4.1.1.6 b) i. – *Global Scenarios*.

Net Zero Scenario means the Net Zero Emissions by 2050 Scenario as published by the International Energy Agency in May 2021.

NNEEC means Northern New England Energy Corporation.

Non-regulated Energy Activity means any activity in the energy sector that is not a Regulated Energy Activity and that is directly or indirectly complementary to a Regulated Energy Activity carried on by Énergir, L.P., whether or not such Regulated Energy Activity is carried on in the same geographical territory, but excluding any oil and gas exploration activity.

Noverco means Noverco Inc.

OHS-Env. Committee means the Occupational Health and Safety and Environment Committee established by the Board that was in existence in fiscal year 2022 up to October 18, 2022.

Paris Agreement means the climate change agreement entered into following negotiations that took place during the 2015 United Nations Climate Change Conference held in Paris as part of the United Nations Framework Convention on Climate Change.

Permitted Economic Activity means any economic activity, other than a Regulated Energy Activity and a Non-regulated Energy Activity, excluding oil and gas exploration activity.

PNGTS means Portland Natural Gas Transmission System.

Price of Carbon means the economic tool which serves to internalize the costs of damages caused by GHG emissions into the market price of a product in order to direct individuals and society towards lower carbon choices. The simplest expression of carbon pricing is the carbon tax. CATS is also a form of carbon pricing.

Régie means the Régie de l’énergie (Quebec) or, depending on the context, its predecessor, the Régie du gaz naturel (Quebec).

Regulated Energy Activity means any activity in the energy sector that is regulated by a regulatory authority, it being understood that any activity in the energy sector which, on August 12, 1991, was regulated by a regulatory authority is deemed to still be regulated.

Regulation 52-110 means *Regulation 52-110 respecting Audit Committees*, as amended from time to time.

Residential Market means primarily single-family dwellings, duplexes, triplexes and condominiums.

RNG means renewable natural gas.

S&P means S&P Global Ratings, a division of S&P Global Inc.

Standard Solar means Standard Solar, Inc.

Status Quo Scenario means the *Status Quo Scenario* published by the Bank of Canada.

Sustainable Development Scenario or SDS means the 2°C or less by 2100 scenario compared to preindustrial levels published by the International Energy Agency.

System Gas means natural gas supplied by Énergir, L.P. rather than by an independent supplier selected by the customer.

TCFD means Task Force on Climate-related Financial Disclosures.

TCPL means TransCanada PipeLines Limited.

TQM means Trans Québec & Maritimes Pipeline Inc., as mandatary for TQM Pipeline and Company, Limited Partnership.

Transco means Vermont Transco LLC.

Transport Solutions means Gaz Métro Transport Solutions, L.P.

Trencap means Trencap, L.P.

TSX means the Toronto Stock Exchange.

Under2 Coalition means a global community of multinational corporations and state and regional governments committed to climate change action.

Unit means an issued and outstanding unit of Énergir, L.P.

Valener Éole means Valener Éole Inc.

Valener Éole 4 means Valener Éole 4 Inc.

VELCO means Vermont Electric Power Company, Inc.

Vermont Gas means Vermont Gas Systems, Inc.

Vermont Gas Board means the board of directors of Vermont Gas.

Vision 2030-2050 means Énergir, L.P.'s strategy, with respect to its natural gas distribution activities in Quebec, on how it will adapt, within the 2030 and 2050 horizons, to the evolving energy context and the impacts of climate change, as described at greater length in Item 4.1.1.6 c) *Resiliency of Énergir, L.P.'s Business Model*.

VPUC means Vermont Public Utility Commission.

Wind Farms 2 and 3 means the wind farms of Wind Farms 2 and 3 GP located on private lands of the Seigneurie de Beaupré owned by the Séminaire de Québec.

Wind Farms 2 and 3 GP means the Seigneurie de Beaupré Wind Farms 2 and 3 General Partnership.

Wind Farm 4 means the wind farm of Wind Farm 4 GP located on private lands of the Seigneurie de Beaupré owned by the Séminaire de Québec.

Wind Farm 4 GP means Seigneurie de Beaupré Wind Farm 4 GP.

ITEM 1 INCORPORATION AND INTERCORPORATE RELATIONSHIPS

1.1 Incorporation and principal holders of Énergir Inc.

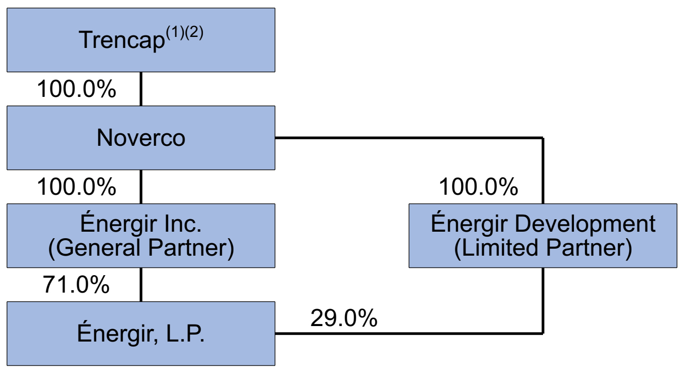
Énergir Inc. was incorporated under the name “Corporation de Gaz Naturel du Québec” and its English version “Quebec Natural Gas Corporation” pursuant to Part I of the *Companies Act* (Quebec) by letters patent dated June 15, 1955. Supplementary letters patent were subsequently issued to it on various occasions, principally to modify its share capital. On February 14, 2011, Énergir Inc. became subject to the Quebec *Business Corporations Act*.

The corporate name of Énergir Inc. (then known as Quebec Natural Gas Corporation) was changed to "Gaz Métropolitain inc." on October 4, 1969. It was changed to "Gaz Métro inc." on November 18, 2003, before finally being changed to "Énergir Inc." on November 29, 2017.

On August 5, 1991, Énergir Inc. (then known as Gaz Métropolitain, inc.) and Énergir, L.P. (then known as Gaz Métropolitain and Company, Limited Partnership) underwent a corporate reorganization pursuant to which Énergir Inc. transferred substantially all of its business and assets to Énergir, L.P. in exchange for Units and the assumption by Énergir, L.P. of substantially all of the liabilities of Énergir Inc., other than the subordinated debt issued to Noverco, its parent company.

Énergir inc.'s head office is located at 1717 du Havre Street, Montréal, Quebec, Canada H2K 2X3.

The following diagram indicates the shareholdings of Énergir Inc. as at September 30, 2022:



(1) As at September 30, 2022, the general partner of Trencap was Capital d’Amérique CDPQ Inc., a subsidiary of CDPQ which, as a limited partner of Trencap, held 80.8956% of its units. Trencap's other limited partner, Fonds de solidarité des travailleurs du Québec (F.T.Q.), held 19.1044% of its units.

(2) In June of 2021, Trencap, then the majority shareholder of Noverco, and IPL System Inc., a subsidiary of Enbridge (which was then Noverco's other shareholder), entered into a final agreement under which Trencap would purchase all of the common and preferred shares of Noverco held by IPL System Inc. The transaction was finalized on December 30, 2021. Since this transaction was completed, Trencap holds all of the shares of Noverco, Énergir Inc.'s sole shareholder.

1.2 Incorporation of Énergir, L.P.

Énergir, L.P. is a limited partnership formed on October 1, 1987 pursuant to the laws of the Province of Quebec under the name “Gaz Plus and Company, Limited Partnership.”

The corporate name of Énergir, L.P. (then known as Gaz Plus and Company, Limited Partnership) was changed to "Gaz Métropolitain and Company, Limited Partnership" on August 5, 1991. It was changed to "Gaz Métro Limited Partnership" on November 18, 2003, before finally being changed to "Énergir, L.P." on November 29, 2017.

Énergir, L.P.’s principal place of business is located at 1717 du Havre Street, Montréal, Quebec, Canada H2K 2X3. Énergir, L.P. is registered as a limited partnership with the Enterprise Registrar (Quebec) and as an extra-provincial limited partnership in each province of Canada other than Quebec.

Énergir Inc. has acted as the General Partner of Énergir, L.P. since the corporate reorganization in 1991 under the Limited Partnership Agreement. As at the date of this Annual Information Form, Énergir Inc. held approximately 71.0% (135,854,066 Units) of the 191,353,030 Units, and the remainder were held by Énergir Development (55,498,964 Units, representing 29.0% of the Units).

1.2.1 Historical Background

The following table describes the main events and dates relevant to Gaz Métro:

Date	Events
August 5, 1991	The Original Limited Partnership Agreement of Énergir, L.P. (then known as Gaz Plus and Company Limited Partnership) was amended and the name was changed to "Gaz Métropolitain and Company, Limited Partnership" as part of a corporate reorganization of Énergir Inc. (then known as Gaz Métropolitain, inc.) and Énergir, L.P. [then known as Gaz Métropolitain and Company, Limited Partnership] pursuant to which Énergir Inc. (then known as Gaz Métropolitain, inc.) transferred substantially all of its business and assets to Énergir, L.P. (then known as Gaz Métropolitain and Company, Limited Partnership) in exchange for Units and the assumption by Énergir, L.P. (then known as Gaz Métropolitain and Company, Limited Partnership) of substantially all of the liabilities of Énergir Inc. (then known as Gaz Métropolitain, inc.), other than the subordinated debt issued to Noverco Inc., its parent company.
September 30, 2010	Énergir, L.P. (then known as Gaz Métro Limited Partnership) reorganized its public ownership structure into a new corporation named "Valener Inc." (now known as Énergir Development). Pursuant to this transaction, the Units held by public holders were exchanged for common shares of Énergir Development (then known as Valener Inc.) on a one-for-one basis. Énergir Development (then known as Valener Inc.) became a partner along with Énergir Inc. (then known as Gaz Métro Inc.) and Gaz Métro Plus Inc., while former public holders became shareholders of Énergir Development (then known as Valener Inc.). In connection with this transaction, the Limited Partnership Agreement was amended so as to, among other things, grant Énergir Development (then known as Valener Inc.) certain rights regarding governance and its growth prospects.
October 25, 2019	The Limited Partnership Agreement was amended following the indirect acquisition of all of issued and outstanding shares of Énergir Development (then known as Valener Inc.) by Noverco on September 27, 2019 for the purposes, among other things, of removing certain rights granted to Énergir Development (then known as Valener Inc.) in 2010 regarding governance and its growth prospects.
December 5, 2019	The Limited Partnership Agreement was amended to remove Gaz Métro Plus Inc. following the redemption and cancellation, by Énergir, L.P., of all of the Units held by Gaz Métro Plus Inc.

1.2.2 Intercorporate Relationships

Énergir, L.P. is a leading energy distributor in Quebec and, through subsidiaries, in Vermont that engages in natural gas distribution activities in Quebec and holds subsidiaries.

The material subsidiary of Énergir, L.P. as at September 30, 2022, is as follows:

Name	Jurisdiction of incorporation	Percentage of voting rights attached to securities beneficially held by Énergir, L.P. or over which Énergir, L.P. exercises control and direction	Description
Green Mountain	Vermont	100.0%	Its core business is the distribution, production, transportation, purchase and sale of electricity in Vermont and, to a lesser extent, electricity transmission in New Hampshire and electricity production in the states of New York, Maine and Connecticut.

The other subsidiaries of Énergir, L.P. each represented (i) less than 10.0% of the consolidated assets of Énergir, L.P. as at September 30, 2022 and (ii) less than 10.0% of Énergir, L.P.'s consolidated revenue for the fiscal year ended September 30, 2022. Altogether, as at September 30, 2022 and for the fiscal year ended September 30, 2022, respectively, the other subsidiaries represented less than 20.0% for each of points (i) and (ii) described above. Énergir, L.P.'s natural gas distribution activity in Quebec and Green Mountain's electricity distribution activity in Vermont accounted for approximately 87.0% of Énergir, L.P.'s consolidated assets as at September 30, 2022 and for approximately 92.0% of its consolidated revenue for fiscal year 2022.

1.2.3 Key Elements of the Limited Partnership Agreement

The following text summarizes the Limited Partnership Agreement. A complete copy of the Agreement is available on the SEDAR website at www.sedar.com.

1.2.3.1 General

Pursuant to the Limited Partnership Agreement, Énergir Inc. has the exclusive power and authority to administer, manage, control and operate the business of Énergir, L.P. and to hold all the rights to its assets, as more fully described under Item 3 *NARRATIVE DESCRIPTION OF ÉNERGIR INC.'S CORE BUSINESS*.

1.2.3.2 Business of Énergir, L.P.

The Limited Partnership Agreement stipulates that Énergir, L.P. shall only carry on Regulated Energy Activities, Non-regulated Energy Activities and Permitted Economic Activities, except that:

i. Énergir, L.P. shall not increase its Interests in Non-regulated Energy Activities if, as a result thereof, the aggregate amount of the Interests of Énergir, L.P. in Non-regulated Energy Activities and in Permitted Economic Activities would exceed 10.0% of the amount of the assets of Énergir, L.P. calculated on the basis of its last annual non-consolidated financial statements plus, if any, the amount of the increase in the assets of Énergir, L.P. resulting from such increase in the Interests of Énergir, L.P. in Non-regulated Energy Activities; and
ii. Énergir, L.P. shall not increase its Interests in Permitted Economic Activities if, as a result thereof, the aggregate amount of the Interests of Énergir, L.P. in Permitted Economic Activities would exceed 5.0% of the amount of the assets of Énergir, L.P. calculated on the basis of its last annual non-consolidated financial statements plus, if any, the amount of the increase in the assets of Énergir, L.P. resulting from such increase in the Interests of Énergir, L.P. in Permitted Economic Activities.

As at September 30, 2022, Énergir, L.P.'s Interests in Non-regulated Energy Activities and in Permitted Economic Activities totalled $144.7 million, representing 2.4% of its non-consolidated assets, and Énergir, L.P. did not have any Interests in Permitted Economic Activities.

Énergir, L.P.'s Interests as at September 30, 2022				
	Non-regulated Energy Activities and Permitted Economic Activities		Permitted Economic Activities only	
	In millions of $	As a % of its non-consolidated assets	In millions of $	As a % of its non-consolidated assets
2022	144.7	2.4	0.0	0.0
2021	125.7	2.3[(1)]	0.0	0.0
2020	470.1	8.1	0.0	0.0

(1) The 2021 Annual Information Form indicated that Énergir, L.P.'s Interests, expressed as a percentage of its non-consolidated assets for the Non-Regulated Energy Activities and Permitted Economic Activities, stood at 2.1%. It should have indicated 2.3%.

1.2.3.3 Pre-Emptive Right

Any new units to be issued by Énergir, L.P. shall first be offered to each of Énergir Development and Énergir Inc., which may purchase a number of new units corresponding to their respective pro rata share of Units at fair market value, as determined by the Board. Each of Énergir Inc. and Énergir Development shall have a period of 60 days to confirm its intention to exercise its pre-emptive right and commit to complete its capital injection, failing which it shall be deemed to have waived its pre-emptive right. If that pre-emptive right is exercised, it shall have up to six months from the date of expiry of the 60-day acceptance period to complete its capital injection, failing which no new units shall be issued to such party, without limiting any available recourses of Énergir, L.P. In cases where Énergir, L.P. requires an urgent injection of capital before the expiry of the six-month capital injection period (as determined by the Board, in its entire discretion), if Énergir Development and Énergir Inc. cannot concurrently fund any such required capital injection by the proposed date of closing of the issue of new units, the party that agrees to participate alone in such urgent injection shall be entitled to receive from Énergir, L.P. reasonable supporting/financing fees on the portion injected for the subscription of new units (based on comparable market fees) until the pro rata injection by the other party is completed, or the expiry of the 60-day acceptance period if the other party does not exercise its pre-emptive right in due time.

1.2.3.4 Distribution Practice

It is intended that Énergir, L.P. will continue to distribute substantially all of its net income for a given fiscal year, and the Limited Partnership Agreement provides that Énergir, L.P. will distribute not less than 85.0% of its net income excluding non-recurring items, save and except for exceptions required (i) for the benefit of bondholders or lenders of Énergir, L.P. or Énergir Inc., as applicable, (ii) to ensure continued compliance with terms and conditions under the credit facilities and trust deeds of Énergir, L.P. and Énergir Inc., (iii) to comply with applicable regulations and laws, and (iv) to comply with any requirements of a regulatory authority. In addition, if Énergir Inc., as general partner, determines that it is appropriate, for any other reason (including as may be required for investments in the business, financing requirements or capital structure realignment of Énergir, L.P.), to distribute less than 85.0% of the net income excluding non-recurring items, it may cause Énergir, L.P. to do so provided that the resolution of the Board authorizing such lesser distribution has been adopted with the approval of at least 90.0% of the votes cast by directors.

1.2.3.5 Dissolution of Énergir, L.P.

The Limited Partnership Agreement also stipulates that Énergir, L.P. shall carry on its activities until September 30, 2090, unless it is dissolved before, and that its capital shall consist of an unlimited number of units, the general partner being responsible for their issuance.

ITEM 2 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Énergir Inc.

As explained under Item 3 *NARRATIVE DESCRIPTION OF ÉNERGIR INC'S CORE BUSINESS*, Énergir Inc.'s main activity consists in acting as general partner of Énergir, L.P.

In the course of each fiscal year, certain events and conditions influence the general development of Énergir Inc.'s business. Following are the main events and conditions that have influenced such development over the last three fiscal years and the events and conditions subsequent to each of these fiscal years:

Énergir Inc.'s Core Business		
2022	**2021**	**2020**
A new credit agreement was entered into on July 13, 2022 between Énergir Inc. and Énergir, L.P. and their banking consortium. This agreement provides for a secured revolving credit facility of $800.0 million expiring in July 2027 and replacing the credit facility set up in March 2012 by Énergir Inc., as borrower, and Énergir, L.P., as guarantor. Énergir, L.P. became the sole borrower under the credit agreement starting in September 2022. The agreement is guaranteed by a universal hypothec on all assets of Énergir, L.P.	—	Issuance, on April 16, 2020, by way of a private placement, of first mortgage bonds for an amount of $300.0 million, secured by Énergir, L.P. as to the payment of principal and interest, together with collateral security backed by the assets of Énergir Inc. and Énergir, L.P., the proceeds of which were loaned to Énergir, L.P. on similar terms and conditions to the first mortgage bonds.

2.2 Énergir, L.P.

With more than $9 billion in assets, Énergir, L.P., on a consolidated basis, is a diversified energy business whose mission is to meet the energy needs of approximately 540,000 customers and the communities that it and its subsidiaries serve in Quebec and Vermont in an increasingly sustainable way. Énergir, L.P. is the largest natural gas distribution company in Quebec; through its joint ventures, it also generates electricity from wind power. And through its subsidiaries and other investments, Énergir L.P. has a presence in the United States, where it generates electricity from hydraulic, wind, and solar sources; it is also the largest electricity distributor and the sole pipeline natural gas distributor in the State of Vermont. Énergir, L.P. values energy efficiency and invests its resources and continues its efforts in innovative energy projects such as renewable natural gas and liquefied and compressed natural gas. Through its subsidiaries, it also provides a variety of energy services. Énergir, L.P. strives to become the partner of choice for those seeking a better energy future.

Main Business Segments

Énergir, L.P. has five main business segments: (i) Energy Distribution, (ii) Transportation of Natural Gas, (iii) Electricity Production, (iv) Energy Services, Storage and Other, and (v) Corporate Affairs.

An outlook on the business, the mission and the strategy of Énergir, L.P. can be found in section A) *Overview of Énergir Inc. and Other* on pages 3 to 11 of the 2022 MD&A.

Main Events and Conditions

In the course of each fiscal year, a number of events and conditions influence the general development of Énergir, L.P.'s business. Following are the main events and conditions that have influenced such development over the last three fiscal years:

Regulatory Framework		
Natural Gas Distribution in Quebec		
Rate of Return and Incentive		
2022	**2021**	**2020**
▪ In November 2021, Régie decision approving the 2022 rate case presenting, among other things, an average rate base of $2.383 million, a $96 million increase over the 2021 rate case, and an 8.90% rate of return on the deemed common equity as approved in November 2019. For fiscal year 2022, the rate case approved by the Régie provided for an overall rate increase of 15.59% for all services.	▪ In November 2020, Régie decision approving the 2021 rate case presenting, among other things, an average rate base of $2.287 million, a $91 million increase over the 2020 rate case, and an 8.90% rate of return on the deemed common equity as approved in November 2019. For fiscal year 2021, the rate case approved by the Régie provided for an overall rate increase of 5.90% for all services.	▪ In November 2019, Régie decision approving (i) the introduction of a revenue decoupling mechanism, (ii) a new method for sharing overearnings and shortfalls, (iii) renewal of the 8.90% rate of return on the deemed common equity for fiscal years 2021 and 2022, (iv) an average overall 14.3% decrease in rates for all services, and (v) an average base rate of $2.196 million, a $39 million increase over the 2019 base rate.
▪ In March 2022, Régie decision approving the regulatory framework determining certain terms and conditions as regards setting rates for fiscal years 2023 to 2025; renewing the methods for sharing fiscal-year-end shortfalls and overearnings and for revenue decoupling mechanism; and authorizing proposed adjustments to the setting of operating expenses.	—	—

Regulatory Framework		
Electricity Distribution in Vermont		
2022	**2021**	**2020**
▪ Green Mountain's base rate of return for fiscal year 2022 was set by the VPUC at 8.57%.	▪ Green Mountain's base rate of return for fiscal year 2021 was set by the VPUC at 8.20%.	▪ Green Mountain's base rate of return for fiscal year 2020 was set by the VPUC at 9.06%.
▪ In August 2022, the VPUC decided to approve, with minor adjustments, a new multi-year regulation plan determining the regulatory framework that Green Mountain will use to set rates and establish services for three years starting October 1, 2022.	—	—

Energy Distribution, Market Developments		
Price of Natural Gas and Market Position in Quebec		
2022	**2021**	**2020**
▪ In fiscal year 2022, although the price for natural gas rose sharply in North America, it remained markedly lower than global prices. Since April 2022, prices climbed to reach levels above the averages of the last decade. Throughout the summer, the use of natural gas to produce electricity exceeded historical averages. From April 2022 to August 2022, U.S. demand for natural gas rose 5.4%, while natural gas production in the U.S. rose 3.6%, an increase that is lower than that for demand. This gap between production and demand contributed to limiting the quantities of natural gas injected into storage and pushed natural gas prices up in fiscal year 2022.	▪ In fiscal year 2021, natural gas prices rose sharply due to the fact that natural gas production in the U.S. delayed in regaining late 2019 production levels, U.S. LNG exports were strong and storage was weak, notably in the Southern United States.	▪ In fiscal year 2020, natural gas prices continued their downward trend owing to an abundant continental supply and higher than normal winter temperatures. Although production has started to decline significantly, high storage levels helped keep price increases in check up to the 4th quarter.
▪ Overall 2.6% increase in natural gas deliveries in Quebec as a result of the following: in the Commercial Market: stronger consumption due mainly to less stringent COVID-19 public health restrictions in fiscal year 2022 and, in the Industrial Market: increased consumption, more specifically in the energy production sector.	▪ Overall 3.9% increase in natural gas deliveries in Quebec as a result of the following: in the Industrial Market: stronger consumption, notably in the metallurgy sector, due mainly to the gradual lifting of the COVID-19 public health measures and, in the Commercial Market: increased consumption despite the adverse effects resulting from the continuation of certain public health measures.	▪ Overall 3.7% drop in natural gas deliveries in Quebec as a result of the following: weaker consumption, especially in the Commercial and Industrial Markets, more specifically in the metallurgy sector, due to COVID-19.

Energy Distribution, Market Developments		
Price of Electricity and Market Position in Vermont		
2022	**2021**	**2020**
▪ Electricity prices far more volatile for most of fiscal year 2022 explained as follows: the price of electricity in New England is strongly correlated to the price of natural gas, which increased in fiscal year 2022, and the availability of LNG was significantly impacted by the war in Ukraine.	▪ Relatively stable electricity prices in the winter of 2021 owing to the more than adequate supply in New England's electric energy market.	▪ Drop in electricity prices in the winter of 2020, owing to weak natural gas prices and warmer temperatures in the last three months of winter.

Financing Activities		
Green Mountain Power		
2022	**2021**	**2020**
▪ Bond purchase agreement entered into on September 23, 2022, resulting in the issuance, by way of private placement, of a series of first mortgage bonds for an amount of US$25.0 million.	▪ Bond purchase agreement entered into on December 15, 2020 resulting in the issuance, by way of private placement, of two series of first mortgage bonds for an aggregate principal amount of US$60.0 million, namely a series of US$35.0 million and a series of US$25.0 million.	▪ Bond purchase agreement entered into on December 18, 2019 resulting in the issuance, by way of private placement, of two series of first mortgage bonds for an aggregate principal amount of US$40.0 million, namely a series of US$15.0 million and a series of US$25.0 million.

Financing Activities		
Énergir, L.P.		
2022	**2021**	**2020**
▪ Issuance, on September 27, 2022, by way of private placement, of first mortgage bonds for an amount of $200.0 million, secured by a hypothec on the assets of Énergir, L.P., the proceeds of which issuance were used to repay the existing debts and for the general purposes of Énergir, L.P.	▪ Issuance, on June 28, 2021, of 5,434,783 new Units at a price of $23.00 per Unit, for total proceeds of approximately $125.0 million, issued to Énergir Inc. and Énergir Development (then known as Valener Inc.) on the basis of their respective holdings.	—
▪ A new credit agreement was entered into on July 13, 2022 between Énergir Inc., Énergir, L.P. and their banking consortium. This agreement provides for a secured revolving credit facility of $800.0 million expiring in July 2027 and replacing the credit facility set up in March 2012 by Énergir Inc., as borrower, and Énergir, L.P., as guarantor. Énergir, L.P. became the sole borrower under the credit agreement starting in September 2022. The agreement is guaranteed by a universal hypothec on all assets of Énergir, L.P.	▪ Issuance, on April 1, 2021, of 9,782,609 new Units at a price of $23.00 per Unit, for total proceeds of approximately $225.0 million, issued to Énergir Inc. and Énergir Development (then known as Valener Inc.) on the basis of their respective holdings.	—
▪ Issuance, on July 13, 2022, of an information circular for the issuance of short-term notes (also called commercial paper) up to an amount of $800.0 million, backed by the previously described credit agreement.	▪ Issuance, on January 5, 2021, of 2,173,913 new Units at a price of $23.00 per Unit, for total proceeds of approximately $50.0 million, issued to Énergir Inc. and Énergir Development (then known as Valener Inc.) on the basis of their respective holdings.	—
▪ Issuance, on February 9, 2022, by way of private placement, of first mortgage bonds for an amount of $325.0 million, secured by a hypothec on the assets of Énergir, L.P., the proceeds of which issuance were used to repay the existing debts and for the general purposes of Énergir, L.P.	▪ Issuance, on December 1, 2020, of 2,173,913 new Units at a price of $23.00 per Unit, for total proceeds of approximately $50.0 million, issued to Énergir Inc. and Énergir Development (then known as Valener Inc.) on the basis of their respective holdings.	—

Additional information regarding main developments in Énergir, L.P.'s business can be found in section D) *Segment Results* on pages 18 to 26 of the 2022 MD&A.

ITEM 3 NARRATIVE DESCRIPTION OF ÉNERGIR INC.'S CORE BUSINESS

As part of the 1991 corporate reorganization, Énergir Inc. agreed not to conduct any activity and not to acquire any property, security or asset except those acquired or held in its capacity as general partner of Énergir, L.P. and those held by Noverco at the time of its amalgamation with Énergir Inc. or acquired in replacement thereof, and other assets the cost of which does not exceed 1.0% of its total consolidated assets. As at September 30, 2022, Énergir Inc. was in compliance with this obligation.

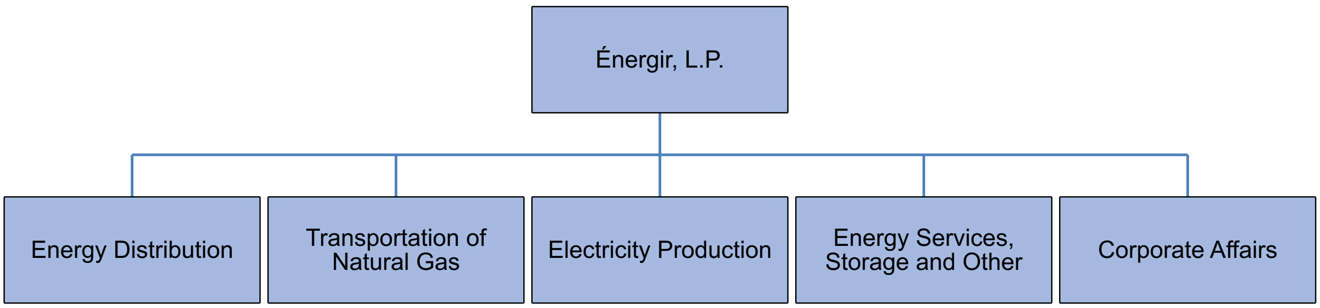
Énergir Inc. also agreed that it would not assume any liabilities, except (i) those related to borrowings destined to be relended to Énergir, L.P., (ii) the subordinated debentures and (iii) any other debt for an aggregate amount that does not exceed 1.0% of its total consolidated assets, the whole as defined in the trust deeds. As at September 30, 2022, Énergir Inc. was in compliance with this obligation.

Énergir Inc. must exercise its powers and discharge its duties with reasonable skill and with all the care of a prudent director, as would a director of a corporation under similar circumstances. The authority and powers vested in Énergir Inc. to manage, control and operate the business of Énergir, L.P. are broad and include all the powers necessary or incidental to the exercise of Énergir, L.P.'s business. Énergir Inc. receives a fee of $50,000 per fiscal year and is entitled to charge Énergir, L.P. for all of the expenses it incurs in acting as general partner.

The removal of Énergir Inc. as general partner of Énergir, L.P. must be approved by an extraordinary resolution of the partners of Énergir, L.P. Moreover, Énergir Inc. may not cease to act as general partner nor dispose of all or part of its interest in the Units without an extraordinary resolution of the bondholders pursuant to the trust, hypothec, mortgage and pledge deeds governing the first mortgage bonds of Énergir Inc.

ITEM 4 NARRATIVE DESCRIPTION OF ÉNERGIR, L.P.'S FIVE MAIN BUSINESS SEGMENTS

The following diagram illustrates Énergir, L.P.'s five main business segments:



Énergir, L.P. (Quebec, Canada) *Regulated*	**TQM**[3] (Canada) *Regulated*	**Wind Farms 2 and 3 GP**[6] (Quebec, Canada) *Non-regulated*	**Gaz Métro LNG**[8] (Quebec, Canada) *Non-regulated*	**NNEEC**[14] (Vermont, U.S.A.) *Non-regulated*
Vermont Gas[1] (Vermont, U.S.A.) *Regulated*	**Champion Pipe Line Corporation Limited**[4] (Canada) *Regulated*	**Wind Farm 4 GP**[7] (Quebec, Canada) *Non-regulated*	**Transport Solutions**[9] (Quebec, Canada) *Non-regulated*	
Green Mountain[1][2] (Vermont, U.S.A.) *Regulated*	**PNGTS**[5] (Maine, U.S.A.) *Regulated*		**Énergir Management**[10] (Quebec, Canada) *Non-regulated*	
			Énergir, chaleur et climatisation urbaines, s.e.c.[11] (Quebec, Canada) *Non-regulated*	
			Intragas[12] (Quebec, Canada) *Regulated*[13]	

(1) Wholly owned by NNEEC.
(2) Green Mountain holds a significant ownership interest in Transco (direct and indirect totalling 77.1%) and in Velco (38.8% direct).
(3) 50.0%-owned by Gaz Métro Holding Inc., a wholly owned subsidiary of Énergir, L.P.
(4) Wholly owned by Énergir, L.P.
(5) 38.3%-owned by Northern New England Investment Company Inc., a wholly owned subsidiary of NNEEC.
(6) Ownership interest 50.0%-held by Beaupré Éole, which is 51.0%-owned by Gaz Métro Éole, a wholly owned subsidiary of Énergir, L.P.
(7) Ownership interest 50.0%-held by Beaupré Éole 4, which is 51.0%-owned by Gaz Métro Éole 4, a wholly owned subsidiary of Énergir, L.P.
(8) 58.0%-owned by Énergir, L.P.
(9) Wholly owned by Énergir, L.P.
(10) Wholly owned by Énergir, L.P. On June 30, 2022, Énergir Management divested itself of some of its assets and liabilities so as to dispose of a portion of its operations.
(11) Wholly owned by CDH Solutions & Operations Limited Partnership, a wholly owned subsidiary of Énergir Management.
(12) Ownership interests held by Gaz Métro Holding Inc., a wholly owned subsidiary of Énergir, L.P., ranging from 40.0% to 60.0% depending on the businesses making up the Group.
(13) Only the activity of Intragas, Limited Partnership is regulated. The activities of the other enterprises of the Intragas Group are not regulated.
(14) Owned directly (96.34%) and indirectly (3.66%) by Énergir, L.P.

Some of the more specific elements of this activity, such as energy distribution, are described in detail below. For more information about this activity, reference is made to the 2022 MD&A (available on the SEDAR website at www.sedar.com), which should be read in conjunction with the 2022 Financial Statements (also available on the SEDAR website).

One of Énergir L.P.'s core businesses is the distribution of natural gas in Quebec (included in the Energy Distribution Segment). In fiscal year 2022, this activity generated approximately 58.0%[(2)] of the consolidated net income attributable to the partners of Énergir, L.P., compared to 72.0% during fiscal year 2021. Énergir, L.P. distributes approximately 97.0% of the natural gas consumed in Quebec.

4.1 Energy Distribution

The Energy Distribution Segment includes the natural gas distribution activities in Quebec carried on by Énergir, L.P. and in Vermont carried on by Vermont Gas and the electricity distribution activities in Vermont carried on by Green Mountain.

It should also be noted that energy distribution is subject to seasonal fluctuations, with most natural gas and electricity demand occurring during the winter heating season and the summer air conditioning season.

4.1.1 Distribution of Natural Gas in Quebec

4.1.1.1 Regulatory Process and Rates

a) Regulatory Process

The transportation, distribution, supply and storage of natural gas delivered through pipelines in Quebec are subject, among other things, to the provisions of the *Act respecting the Régie de l'énergie* (Quebec) and the *Building Act* (Quebec), and to certain provisions of the *Gas, Water and Electricity Companies Act* (Quebec).

Énergir, L.P.'s natural gas distribution activity in Quebec is regulated by the Régie. The Régie's primary role is to set or modify the rates and conditions for the supply, transportation and delivery of natural gas by a distributor, as well as the rates for storage. The Régie also performs other functions, including overseeing the activities of a distributor, determining its rate of return, authorizing investments, reviewing consumer complaints, and setting the conditions for the installation of a distributor's facilities in municipalities.

Within its territory, as a corollary to its exclusive right to operate a natural gas distribution system and to transmit and deliver by pipeline natural gas intended for consumption, Énergir, L.P. has the obligation to supply and deliver natural gas to anyone who requests it, and to deliver natural gas that some users have chosen to purchase from a third party. However, under certain conditions, the *Act respecting the Régie de l'énergi*e (Quebec) allows the distributor to apply to the Régie to be exempted from the requirement to deliver natural gas or to provide service to a consumer.

In reviewing an application to set or modify a rate, the Régie must, among other things, determine the distributor's rate base, including, in particular, the unamortized balance of the investments that were made by the distributor to provide such service. The Régie must also determine the aggregate expenses it considers necessary to cover the cost of providing the service. It must also allow a reasonable return on the distributor's rate base. This return reflects the cost of financing the capital structure that the Régie considers appropriate to finance the distributor's rate base. It is determined based on the actual cost and, when applicable, the anticipated cost of debt, the authorized return on partners' deemed preferred equity and the return on partners' deemed common equity that the Régie considers reasonable. The Régie must also provide measures or incentive mechanisms to improve the distributor's performance and satisfaction of customer needs.

The cost of natural gas is fully reflected in supply rates billed to customers by means of an automatic monthly adjustment mechanism established for this purpose, whereby variations are levelled over a forward-looking, moving 12-month period.

[(2)] Consolidated net income attributable to the partners of Énergir, L.P. for fiscal year 2022 includes a $26.8 million unfavourable impact related to adjustments excluded from ongoing operations. The adjustments' amount is explained by a change in the tax treatment of the depreciation of investments in information technology development ($13.8 million), Énergir Management's disposal of some of its assets and liabilities ($8.6 million), and the writing-off of assets associated with the implementation of a customer information system ($4.4 million). For more information on these adjustments, see the 2022 MD&A. Had it not been for these items, this percentage for fiscal year 2022 would have been approximately 57.0%.

In a decision dated December 19, 1990, the Régie determined that the following principles applied to the 1992 base year and to any other subsequent rate year:

i. for regulatory purposes and for determining the return on Énergir, L.P.'s rate base, the Régie will use a deemed defined capital structure and financing costs that are compatible with such capital structure, including a rate of return on the partners' average equity;

ii. as Énergir, L.P.'s net income is taxable in the hands of the partners, the Régie will recognize the tax consequences and will take into account, in determining Énergir, L.P.'s operating expenses, deemed taxes related to current income taxes, large corporations tax and deemed capital tax (which have both since been abolished).

For rate-setting purposes, the capital structure currently recognized by the Régie for the distribution of natural gas in Quebec is 54.0% in the form of debt, 7.5% in the form of deemed preferred equity and 38.5% in the form of partners' deemed common equity. The deemed preferred shares are remunerated at the market rate at the time of their deemed replacement. Remuneration on partners' deemed common equity shall be at the rate authorized by the Régie. During the 2022 calendar year, the Régie authorized maintaining the same rate of return of 8.9% that prevailed during fiscal years 2020 to 2022 for fiscal years 2023, 2024 and 2025. Deemed current income taxes are calculated as if the August 1991 corporate reorganization had not taken place and assuming that Énergir, L.P. is a taxable Canadian corporation.

In a decision dated November 11, 2019, the Régie approved the implementation of a revenue decoupling mechanism for a three-year period. Under this mechanism, which it renewed until 2025 in its March 3, 2022 decision, all variances between the authorized required revenue by the Régie and the actual costs generated by distribution rates are refunded to the customer in full. Consequently, this mechanism reduces the probability of any productivity gains and shortfalls associated with fluctuations in normalized natural gas volumes. The goal of this mechanism is, among other things, to evaluate whether Énergir, L.P. is able to manage its costs properly, regardless of the volumes distributed. This mechanism also helps limit any obstacles to energy efficiency.

Additional information regarding Énergir, L.P.'s regulatory framework can be found in section D) *Segment Results* on pages 19 and 21 of the 2022 MD&A.

b) Main Decisions by the Régie

Additional information regarding the main decisions by the Régie, particularly in connection with the 2022 rate case, can be found in section D) *Segment Results* on page 20 of the 2022 MD&A as well as in Note 6 to the 2022 Financial Statements.

4.1.1.2 Gas Supply

a) Natural Gas Supply Situation

Additional information regarding the natural gas supply situation can be found in section B) *Conditions in the Energy Market and for Énergir, L.P.* on pages 11 to 13 of the 2022 MD&A.

b) Direct Purchases

Énergir, L.P.'s customers can purchase their own natural gas directly from a supplier of their choice. In that case, direct purchase customers generally entrust Énergir, L.P. with the responsibility of transporting the natural gas from the designated supply location up to the territory covered by its exclusive distribution right. Some customers assume responsibility for transporting the natural gas to Énergir, L.P.'s distribution system. During fiscal year 2022, direct purchases accounted for approximately 58.7% of all volumes delivered to Énergir, L.P.'s customers, compared to approximately 62.7% during the previous year.

c) System Gas

System Gas deliveries accounted for approximately 41.3% of all deliveries during fiscal year 2022, compared to approximately 37.3% during the previous fiscal year. Énergir, L.P. supplies System Gas to customers who do not choose to obtain such gas themselves directly from another supplier.

To service its System Gas customers, Énergir, L.P. has annual supply contracts with a number of suppliers. The prices that Énergir, L.P. pays are determined using a recognized published index established on the basis of the prices for a particular period at the Empress (Alberta), Dawn (Ontario) or Henry (Louisiana) hubs, as the case may be, to which a premium, negotiated by the parties, is added. Énergir, L.P. also buys natural gas on a spot basis to adapt to demand fluctuations and the operating conditions of its system.

During fiscal year 2022, Énergir, L.P. acquired 29.6% of the natural gas required to service its System Gas customers at the Empress Hub (Alberta) (compared to 38.02% during the previous fiscal year), 67.4% at the Dawn Hub (Ontario) (compared to 61.78% during the previous fiscal year), 2.7% at the Parkway Hub (Ontario) (compared to 0% during the previous fiscal year) and 0.3% in Quebec[(3)] (compared to 0.2% during the previous fiscal year).

d) Transportation

Other than the two gas pipelines operated by Champion Pipe Line Corporation Limited, the only two pipelines that supply Énergir, L.P. are owned by TCPL and TQM, the latter being a subcontractor to TCPL. Despite this situation, Énergir, L.P. built up a diversified transportation capacity portfolio in terms of maturities and points of origin. Most transportation capacities in the portfolio will be available until October 31, 2026. Énergir, L.P. has the transportation capacities required to carry the natural gas of all of its customers (including direct purchase customers that have entrusted Énergir, L.P. with the responsibility of transporting the natural gas from the designated supply location up to the territory covered by its exclusive distribution right). Consequently, during fiscal year 2022, nearly 90.4%[(4)] of the transportation capacities targeted by the various transportation contracts were for supplies from the Dawn Hub (Ontario) and approximately 9.6%[(5)] for supplies from the Empress Hub (Alberta).

The transportation contracts are not directly linked with a particular source of natural gas supply. Not linking transportation contracts with natural gas supply allows Énergir, L.P. flexibility in obtaining its own natural gas supply.

To transport natural gas up to the territory covered by its exclusive distribution right, Énergir, L.P. has transportation contracts:

- with Enbridge Gas to transport the natural gas from Dawn (Ontario) up to the Parkway Hub (Ontario) and TCPL to transport the natural gas from the Parkway Hub (Ontario) up to the territory covered by its exclusive distribution right; or
- with TCPL to transport the natural gas from the Empress Hub (Alberta) up to the territory covered by its exclusive distribution right.

Énergir, L.P. also has transportation contracts obtained on the secondary market between Dawn (Ontario) and the territory covered by its exclusive distribution right.

Énergir, L.P. may also sign spot contracts with suppliers for gas deliveries directly to the territory covered by its exclusive distribution right as a complement to its own transportation capacity, primarily during the winter period.

For more information regarding the transportation of natural gas, see sections B) *Conditions in the Energy Market and for Énergir, L.P.* and D) *Segment Results* on pages 11 to 13, 24 and 25 of the 2022 MD&A.

e) Storage Required by the Natural Gas Distributor

Natural gas distribution is a seasonal activity, with most natural gas deliveries occurring in winter. Moreover, during the winter months, daily demand for natural gas fluctuates with the temperature. As such, Énergir, L.P. uses storage facilities to:

- take delivery of natural gas on favourable terms during the off-peak (summer) period with a view to withdrawing it and distributing it in winter;
- balance demand and deliveries of natural gas on a daily basis;
- mitigate the risk of a natural gas supply shortage; and
- effectively manage the cost of natural gas during the winter months.

For this purpose, Énergir, L.P. has natural gas underground storage contracts in Dawn (Ontario) under medium-term agreements with Enbridge Gas with various expiry dates. Énergir, L.P. also has two long-term natural gas storage service contracts with Intragas, Limited Partnership (part of Intragas). Peak winter demand is supplied by the LSR Plant.

(3) The natural gas acquired in Quebec was essentially refined biogas and RNG.
(4) Capacities required to transport the System Gas and natural gas of direct purchase customers. Direct purchase customers must deliver their gas to Énergir, L.P. at the Dawn Hub (Ontario).
(5) Capacities required to transport the System Gas.

The transportation and storage contracts referred to under Items d) and e) above are more fully described under Item 10.2.4.2 *Operating Contracts (Énergir, L.P.)*.

4.1.1.3 Market

a) Normalized Deliveries

For fiscal years 2022 and 2021, normalized deliveries of natural gas in Quebec (for normal temperatures and wind velocity) and revenues were as follows:

Normalized Natural Gas Deliveries in Quebec and Revenues Generated								
	Deliveries (10^6m^3)		% of Gas Delivered by Market		Revenues (millions of $)		% Revenues by Market	
	2022	2021	2022	2021	2022	2021	2022	2021
Industrial Market								
Firm service	3,620.8	3,609.5	57.9	59.2	623.4	443.0	34.5	33.5
Interruptible Service	330.2	294.8	5.3	4.9	49.2	22.6	2.7	1.7
Commercial Market	1,670.0	1,571.1	26.7	25.8	770.1	569.6	42.7	43.0
Residential Market	629.3	618.0	10.1	10.1	363.5	289.1	20.1	21.8
Total	**6,250.3**	**6,093.4**	**100.0**	**100.0**	**1,806.2**	**1,324.3**	**100.0**	**100.0**

In fiscal year 2022, normalized natural gas deliveries therefore rose 2.6% compared to the preceding fiscal year. This increase, seen mainly in the Commercial Market, results from the less stringent COVID-19 public health restrictions of fiscal year 2022 that favoured a certain resumption of activities. To a lesser extent, the Industrial Market is also seeing increased consumption, specifically in the energy production sector.

Natural gas consumption is influenced by a number of factors, including temperature fluctuations, technological innovations and energy efficiency initiatives.

The Residential and Commercial Markets embrace technological innovation by adopting high-efficiency equipment and other technologies, such as aerothermal and geothermal heat pumps. In Commercial and Industrial Markets, innovation can be seen in the increasing number of heat recovery systems. Technological innovation also helps customers realize energy savings by improving building envelopes to reduce heating costs or by adopting technologies to effectively manage energy consumption.

Énergir, L.P. began implementing its first energy efficiency programs in 2001. It currently offers more than seven programs that propose a variety of efficiency initiatives ranging from grants for the purchase of high-efficiency appliances to the recommissioning of mechanical systems and installation of innovative solar air preheating systems.

On November 1, 2020, the *Act mainly to ensure the effective governance of the fight against climate change and to promote electrification* came into force. This act provides, among other things, (i) for the abolishment of Transition énergétique Québec ("**TEQ**") and (ii) the transfer of its functions and resources to the Minister of Energy and Natural Resources. The five-year transition, innovation and efficiency master plan previously prepared by the TEQ remains in force, and has been extended to 2026. This master plan still lists the programs and measures implemented by the ministries, organizations and energy distributors (including Énergir, L.P.) so as to achieve the energy efficiency targets, such as those defined by the Quebec government. That target to improve Quebec society's average energy efficiency by at least 1% per year therefore remains in force.

This was the context in which Énergir, L.P., as energy distributor, submitted its energy efficiency programs to the TEQ before it was abolished, which programs aim to generate a 30% savings increase and realize recurring additional GHG reductions of nearly 500,000 tons by September 30, 2023. The master plan was updated on June 10, 2022 by the Quebec government so as to cover the 2024 to 2026 period. This update integrates Énergir, L.P.'s forecasts for the master plan's additional three-year period.

Moreover, Énergir, L.P. must have its programs approved by the Régie. In its decision dated July 30, 2019, the Régie approved Énergir, L.P.'s programs and budgets for fiscal years 2019 to 2023 for the purposes, among other things, of achieving the target set by the government. Overall, Énergir, L.P. is expecting an amount of $129.0 million in subsidies to generate 223.6 10^6m^3 in energy savings. The Régie also rules on the annual adjustments made to the margin of the programs and subsidies so that Énergir, L.P. can maintain the appropriate supply for customers.

In fiscal year 2022, Énergir, L.P. granted its customers nearly $32.5 million to carry out energy efficiency projects. These projects generated a 51.4 $10^6 m^3$ reduction in natural gas and helped prevent the emission of 98,728 tons of GHG.

b) Competitive Position

Fiscal year 2022 was marked by an overall increase in Énergir, L.P.'s supply price (System Gas price) compared to the preceding fiscal year. The annual average was higher than that for the previous fiscal year ($6.60/Gj in 2022 compared to $3.05/Gj in 2021). This therefore resulted in a 116.7% increase in the annual average natural gas supply price compared to fiscal year 2021.

In fiscal year 2022, fuel oil prices also rose compared to the previous fiscal year. Between October 2021 and September 2022, No. 2 fuel oil (also called light fuel oil) traded at an average price that was 88.2% higher than during the previous fiscal year. The price of No. 6 fuel oil (also called heavy fuel oil) was 52.5% higher than during the previous fiscal year.

As explained under Item 4.1.1.5 f) i. *Cap-and-Trade System for Greenhouse Gas Emission Allowances (CATS)*, Énergir, L.P. is subject to CATS. In fiscal year 2022, the average CATS price that Énergir, L.P. billed to its customers for natural gas stood at $1.70/Gj, which is equal to the average price for Énergir, L.P.

Public policies like the Quebec government's 2030 Plan for a Green Economy ("**2030 PGE**") and the Montréal Climate Plan could affect the appeal of natural gas and eventually affect its competitiveness.

The following table gives an overview of the competitive position of natural gas in the main markets served by Énergir, L.P.

Markets		Comparator	Savings in fiscal year 2022	Savings in fiscal year 2021	Average CATS price billed by Énergir, L.P. for the competitive position of natural gas to be neutral in relation to the comparator (as at September 30, 2022)
Residential		Electricity[1]	-0.6% to 25.5% (Depending on the size and age of the dwelling)	20.0% to 41.0% (Depending on the size and age of the dwelling)	From $2.70/GJ to $7.80/GJ (Depending on the size and age of the dwelling)
		No. 2 fuel oil	42.1% to 51.9% (Depending on the size and age of the dwelling and the energy efficiency of devices used)	28.0% to 42.0% (Depending on the size and age of the dwelling and the energy efficiency of devices used)	–[2]
Commercial[3]	Customer consuming less than 100,000 m^3	Electricity	24.2% to 36.0%	44.0% to 52.0%	From $8.40/GJ to $9.10/GJ
		No. 2 fuel oil	48.4% to 58.8%	37.0% to 50.0%	–[2]
	Customer consuming between 100,000 m^3 and 400,000 m^3	Electricity	30.9% to 42.0%	51.0% to 58.0%	From $8.20/GJ to $10.40/GJ
		No. 2 fuel oil	58.4% to 61.6%	50.0% to 54.0%	–[2]
	Customer consuming more than 400,000 m^3	Electricity	42.0% to 45.6%	58.0% to 61.0%	From $10.40/GJ to $11.20/GJ
		No. 2 fuel oil	61.6% to 63.5%	54.0% to 57.0%	–[2]
Industrial[4]		Electricity[5]	42.0%	66.2%	$5.99/GJ
		No. 2 fuel oil	68.1%	66.1%	–[2]
		No. 6 fuel oil	48.3%	54.7%	–[2]

(1) The position presented above is in relation to all Énergir, L.P. customers, namely those using devices that have varying energy efficiencies.

(2) Since petroleum products are also subject to the CATS, and assuming an average CATS price for petroleum products equal to the average CATS price billed by Énergir, L.P., no increase in the latter would have weakened the competitive position of natural gas over No. 2 fuel oil and No. 6 fuel oil. On the contrary, since No. 2 fuel oil and No. 6 fuel oil generate more GHG emissions, any rise in the costs of complying with the CATS would have improved the competitive position of natural gas.

(3) In the case of the Commercial Market customers who purchase their natural gas directly, the cost savings data vary based, among other things, on the terms and conditions of their supply contracts.

(4) In the case of the Industrial Market customers who purchase their natural gas directly (as a vast majority of the Industrial Market customers do), the cost savings data vary based, among other things, on the terms and conditions of their supply contracts. For example, the data provided in the table above relating to the Industrial Market represent a firm-service customer who consumes 10 million m^3 annually.

(5) The industrial customer used for the competitive position analysis consumes electricity at Tariff L.

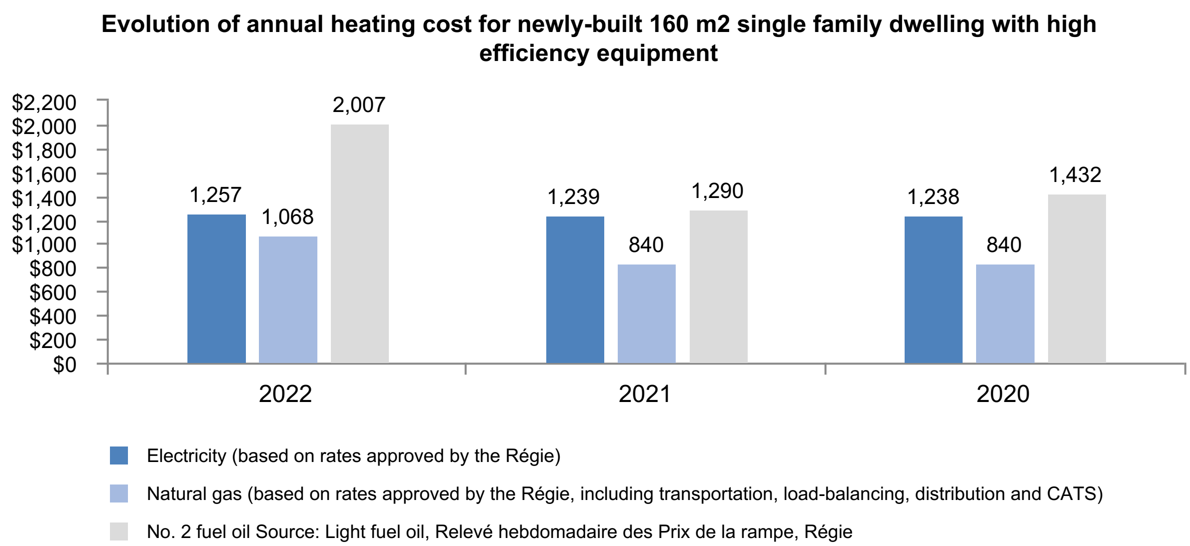
See below for more details on the competitive position of natural gas in these markets.

Residential Market

In terms of residential heating, natural gas and electricity were competing with each other in fiscal year 2022. Based on the annual cost recorded for fiscal year 2022, in most cases customers who chose to heat their dwellings with natural gas using high-efficiency equipment paid a lower cost than they would have paid had they opted for electric heating. However, natural gas's competitive position was less favourable compared to high-efficiency equipment such as heat pumps.

Heating with natural gas instead of No. 2 fuel oil generated savings for all residential customers. The competitive position of natural gas over No. 2 fuel oil gained some ground compared to the previous fiscal year.

The following graph shows the annual cost of using No. 2 fuel oil, electricity and natural gas to heat a single-family dwelling during the fiscal years 2020 to 2022:



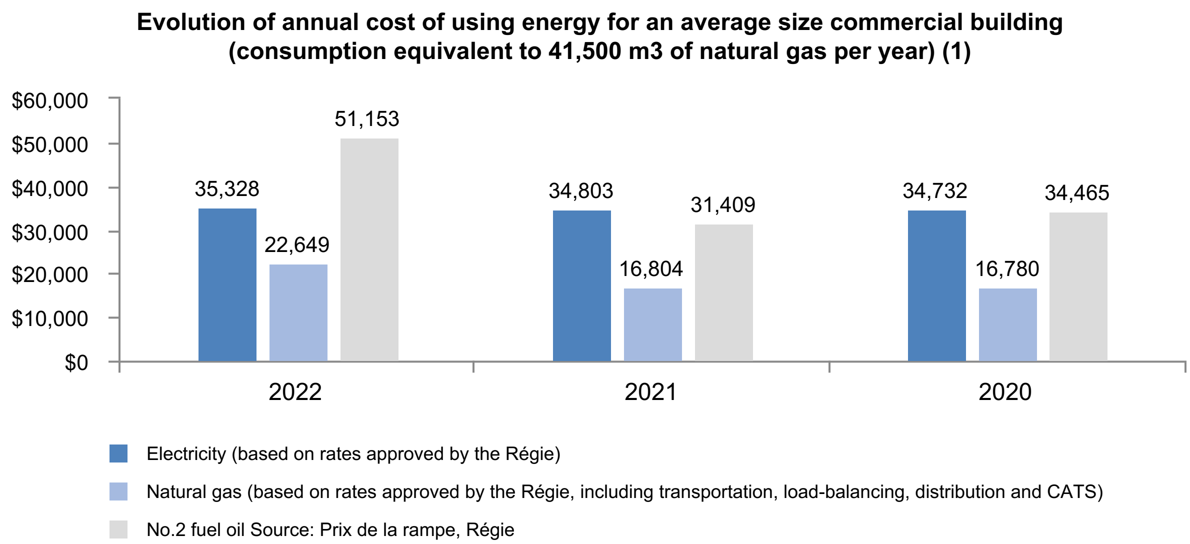
Commercial Market

Based on the annual costs recorded in fiscal year 2022, natural gas maintained its competitive advantage in the Commercial Market. However, natural gas's competitive position was less favourable, perhaps even unfavourable, compared to high-efficiency equipment such as heat pumps.

Despite this favourable situation for natural gas, Hydro-Québec's off-peak marginal rate of 3.88¢ per kilowatt-hour hurt the competitiveness of natural gas in this market, where additional electric equipment has been installed to optimize off-peak electricity consumption.

Again, based on annual costs for fiscal year 2022, natural gas enjoyed a very favourable competitive position over No. 2 fuel oil. Compared to the previous fiscal year, this position is even more favourable.

The following graph shows the annual cost of using No. 2 fuel oil, electricity (excluding optimized off-peak electricity consumption) and natural gas for an average-size commercial customer during the fiscal years 2020 to 2022:

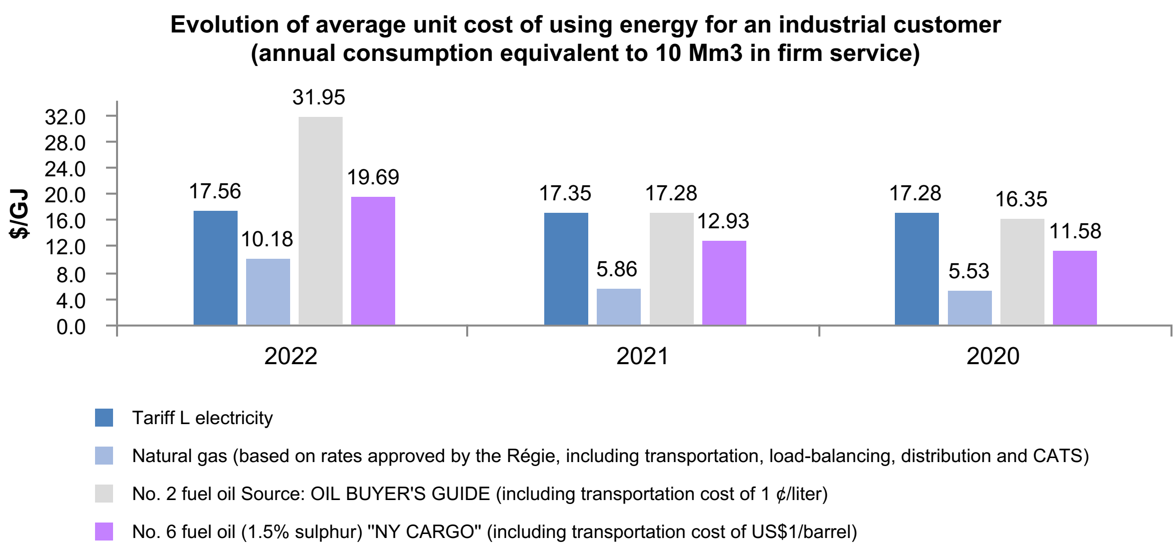


(1) For purposes of calculating the competitive position on the Commercial Market, the analysis consisted of determining the annual cost of using the electricity and No. 2 fuel oil needed to produce the same caloric value as that generated by using 41,500 m^3 of natural gas per year.

Industrial Market

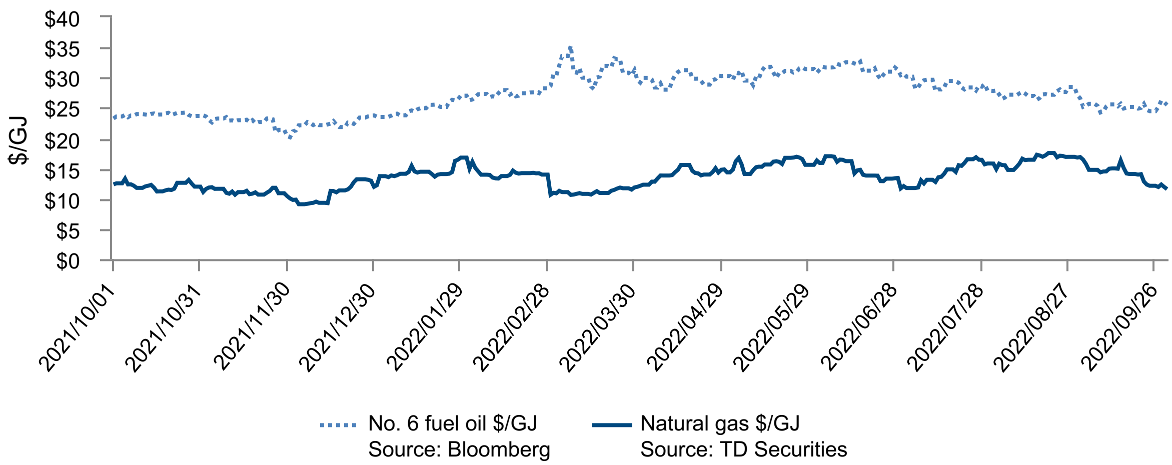
In fiscal year 2022, natural gas held its competitive advantage on the long-term market over electricity, No. 6 fuel oil and No. 2 fuel oil in the Industrial Market. However, despite this favourable situation for natural gas, Hydro-Québec's off-peak rate hurt the competitiveness of natural gas in this market, where additional electric equipment has been installed to optimize off-peak electricity consumption.

The following graph shows the average unit cost of using No. 2 fuel oil, No. 6 fuel oil, electricity and natural gas for a firm-service industrial System Gas customer during the fiscal years 2020 to 2022:



In the spot market, natural gas held its advantage against No. 6 fuel oil in fiscal year 2022. Natural gas had benefited from a favourable competitive position throughout the previous fiscal year.

Evolution of competitive situation of natural gas on industrial market over short term during fiscal year 2022



4.1.1.4 System Operations

Énergir, L.P.'s primary objective with regard to its system operations is to provide continuous safe natural gas supply to all customers. To do so, constant efforts are made to ensure that its facilities are protected through effective system maintenance and improvement programs. Moreover, certain portions of its system have reached a high level of saturation: Énergir, L.P. has therefore commenced developing and implementing measures to remedy this situation.

This year, the annual preventive maintenance program was prioritized and fully completed, with the exception of the indoor facilities inspections, which have only been partially completed[6]. Delays resulting from limited access to customers' buildings due to the healthcare context over the last two years have all been caught up, with the exception of indoor facilities inspections. For these inspections, a new strategy will be developed so as to identify solutions that will improve the execution of these activities within the program's timetables. In addition, municipal and other infrastructure rehabilitation again resulted in major improvement work on Énergir, L.P.'s system. This work was in addition to Énergir, L.P.'s other planned activities designed to keep its system in good condition.

Consistent with the deployment of its action plan to implement a proactive asset management approach, Énergir, L.P. gave priority to actions on assets deemed most likely to have a significant impact on its operations or customers in fiscal year 2022. In its 2023 rate case, Énergir, L.P. anticipated investments of up to $53.4 million, not including major projects, for the continued implementation of this asset management approach.

In the last several years, Énergir, L.P. has noted the occurrence of new natural events, and that these types of events are becoming more frequent (e.g., floods, ice storms, thaw-freeze events triggered by temperature fluctuations, landslides) or more intense (e.g., heavy rain, flooding and extreme heat waves). These events in all likelihood result from climate change.

Accordingly, when Énergir, L.P. reviews its procedures, processes, emergency measures plan and system maintenance and improvement programs, it takes into consideration what impact these new natural events might have on its network and the operation thereof.

Énergir, L.P. has also stepped up its efforts to increase its employees' awareness of the prevention rules associated with such events.

With regard to the third-party damage prevention program, Énergir, L.P. continued its sensitization efforts with the main intervenors, including municipalities, excavation contractors, the Régie du bâtiment and the Commission des

[6] The partial completion of the indoor inspections does not contravene regulatory requirements. Énergir, L.P. is complying with its regulatory obligation to establish a preventive maintenance program.

normes, de l'équité, de la santé et de la sécurité du travail (CNESST). Énergir, L.P. is also actively involved in Info-Excavation's work to promote best practices in this area.

Moreover, Énergir, L.P. complies, among other things, with that portion of standard CAN/CSA-Z662 "Oil and Gas Pipeline Systems" that pertains to the implementation of a documented safety and security and loss management system for pipeline systems (including incidents) in order to ensure personal safety and the protection of property and the environment. Énergir, L.P. elected to have its system audited by an independent auditor every three years. A new certificate attesting that Énergir, L.P.'s system complies with the requirements of this standard was obtained from the Bureau de normalisation du Québec (BNQ) in February 2022.

4.1.1.5 Environmental Protection

a) Environmental Policy

Under its environmental policy, Énergir, L.P. has committed to showing leadership, rigour and determination in pursuing its environmental actions in its activities related to the Quebec natural gas distribution pipeline system and the LSR Plant. It is committed to doing likewise with its customers and the general public in a context of sustainable development.

This environmental policy presents Énergir, L.P.'s commitments regarding the implementation of various actions in three areas: (i) prevention of pollution and protection of the environment, (ii) contribution to the fight against climate change and reduction of pollution, and (iii) the fostering of close ties and collaboration between stakeholders. The policy also states that Énergir, L.P. is committed to maintaining and improving the regular disclosure of its environmental performance.

b) ISO 14001 Standard

Since 2000, Énergir, L.P. has had an ISO 14001-certified environmental management system (the "**Environmental Management System**").

In order to maintain its certification, in February 2022 Énergir, L.P. had an independent auditor perform a recertification audit of its Environmental Management System using the 2015 version of the standard (which audit only takes place once every three years, the two other years being subject to a maintenance audit). Based on the results of that audit, it maintained its ISO 14001 certification.

As part of the Environmental Management System, Énergir, L.P. has identified those of its activities that could have an impact on the environment. It has adopted and implemented a number of procedures to manage the main environmental impacts that could arise from its activities and to ensure compliance with its obligations under applicable laws and regulations. These procedures concern, among other things, the storage and handling of hazardous substances, the management of contaminated soil, the recovery and management of waste, the quantification of GHGs, and applications for environmental authorizations. The procedures are revised regularly. As a result, the Environmental Management System makes it possible to set environmental goals and targets, monitor the results achieved and favour the development of coherent environmental strategic guidelines, among other things.

In addition to the annual audit by an independent auditor, internal audits are performed annually in accordance with ISO 19011 "*Guidelines for quality and/or environmental management systems auditing*" in order to verify whether certain elements of the Environmental Management System are compliant. Moreover, environmental compliance audits are performed to ascertain the extent of the activities' legal compliance.

Finally, a report on the performance of the Environmental Management System is submitted annually to Management. Following its review of this report, Management approves any adjustment or change of direction to be made to the environmental policy, the objectives and targets, or other elements of the Environmental Management System.

The CGEE Committee has the mandate to receive a quarterly report from Management on Énergir, L.P.'s environmental performance and, if necessary, to make recommendations to the Board or, if it has deemed it appropriate, to other committees of the Board. In addition, the Board continues to receive an annual report on environmental risks and issues.

c) Environmental Management Site

Before Énergir, L.P. assumed ownership in 1957 of the land where its head office is located, at 1717 Du Havre Street in Montréal, Quebec, a manufactured gas plant had operated there. The operation of that plant resulted in the contamination of the land. Énergir, L.P. and the Ministry of Environment have entered into an agreement for the environmental management of the land that requires Énergir, L.P. to (i) more precisely define the extent of the contamination and (ii) continuously monitor the contaminants in the land to ensure, among other things, that they are confined to the cadastral boundaries of the land.

Environmental management of the site includes, in particular, supervising the movement of high-density contaminants, groundwater contaminant levels downstream from the property, if necessary, and monitoring building air quality. The reports and analyses conducted under this agreement are submitted annually to the Ministry of Environment. In connection with the agreement with the Ministry of Environment, Énergir, L.P. invested approximately $450,000[7] between 2020 and 2022 to, among other things, manage and monitor the contaminant confinement work.

d) Climate Change and GHG

Under its environmental policy, as in force as at September 30, 2022 and described under Item 4.1.1.5 a) *Environmental Policy*, Énergir, L.P. must, among other things, reduce its own GHG emissions in keeping with Quebec's target. Énergir, L.P. has therefore set itself the objective of reducing its GHG emissions in the context of its natural gas distribution activities and in keeping with Quebec's 2030 target. Quebec, in its 2030 PGE, more fully described below, set itself an emission reduction target of 37.5% below 1990 emissions levels by 2030, compared to its previous 2020 GHG emission reduction target of 20.0% below 1990 levels.

In calendar year 2021, Énergir, L.P.'s GHG emissions totalled 63,549 tonnes of CO_2 eq.,[8] which represents a 21.1% reduction compared to 1990 levels. Énergir, L.P.'s goal is to reduce its GHG emissions in keeping with Quebec's target, which is 37.5% below 1990 levels by 2030.

Compared to 2020 emissions, this is an increase of 8,070 tonnes of CO_2 eq. This increase is due mainly to the fact that in calendar year 2021, the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere* required a global warming potential of 25 to be used for methane emissions instead of a global warming potential of 21. This amendment had the effect of increasing the GHG emissions emitted into the atmosphere for the same quantity of natural gas. Had a global warming potential of 25 been used to calculate Énergir, L.P.'s GHG emissions for calendar year 2020, those emissions would have been 63,372 tonnes of CO_2 eq. This therefore represents a 0.3% increase in Énergir, L.P.'s GHG emissions compared to 2020 levels.

Furthermore, in order to reduce GHG emissions attributable to the natural gas it distributes, Énergir, L.P. has (i) identified or taken measures to increase the quantity of RNG injected in its system, and (ii) implemented a responsible gas supply mechanism the goal of which is to improve the traceability of its natural gas supplies (by, among other things, purchasing natural gas directly from specific producers) and to favour producers who demonstrate they have adopted some of the best practices to reduce the impacts of their operations, notably in terms of methane emissions.

The goal of Énergir, L.P.'s third-party damage prevention program, described at greater length in Item 4.1.1.4 *System Operations*, is also to reduce GHG emissions.

To address climate change risks and opportunities, Énergir, L.P. developed its Vision 2030-2050, which aims to attain carbon neutrality by 2050 in the energy it distributes to its customers. To achieve this goal, Vision 2030-2050 outlines, among others, four initiatives, which include accelerating the growth of energy efficiency efforts. These four initiatives are described at greater length in Item 4.1.1.6 c) *Resiliency of Énergir, L.P.'s Business Model.*

2030 PGE

In 2012, the Government of Quebec adopted the 2013-2020 Climate Change Action Plan, which expired on December 31, 2020. This action plan was replaced by the 2030 PGE, and its first 2021-2026 implementation plan.

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[7] The 2021 AIF indicated that as part of an agreement with the Ministry of Environment, Énergir, L.P. had invested approximately $640,000 between 2018 and 2021 to, among other things, manage and monitor the contaminant confinement work. It should have stated that the amount invested in this work between 2019 and 2021 was approximately $470,000.

[8] All Énergir, L.P. GHG emissions figures under Item 4.1.1.5 d) *Climate Change and GHG* include (i) its GHG emissions, (ii) GHG emissions caused by fugitive emissions and breakdowns, and (iii) emissions resulting from Énergir, L.P.'s vehicle fleet and buildings, even though such emissions did not need to be included in the GHG emissions report to the Ministry of Environment for calendar year 2021. These figures, however, do not include GHG emissions from Énergir, L.P.'s customers.

The 2030 PGE guides the Quebec government’s actions in this area until 2030, the goal being to help it achieve the GHG emission reduction target that the government set for itself for 2030, namely 37.5% below 1990 emissions levels. This first implementation plan has the same five main focal points, notably mitigating and adapting to climate change. Énergir, L.P. is closely monitoring the implementation of the priorities defined in the 2030 PGE and its first action plan to determine how these will impact its growth prospects and competitive position, where applicable. The implementation plan is updated annually to cover the five following years. Consequently, the 2022-2027 implementation plan has the same five main focal points as the 2021-2026 implementation plan. This update provides for injecting an additional $47.5 million into the RNG production support program over five years. This program helps provide financial assistance to (i) feasibility studies, such as projects in Quebec to produce RNG for injection into the natural gas distribution system, and (ii) the completion of these projects. In updating this plan, the government of Quebec is stepping up its efforts to support the completion of energy efficiency and conversion projects under the EcoPerformance program. With Vision 2030-2050, Énergir intends to contribute to a 30.0% total reduction in GHG emissions for natural gas used in the building sector by 2030 compared to 2020 levels, which is in keeping with the 2030 PGE's targets of achieving a 50.0% reduction in building sector emissions by 2030. For more information on Vision 2030-2050, please refer to Item 4.1.1.6 c) *Resiliency of Énergir, L.P.'s Business Model.*

e) ESG

In fiscal year 2022, Énergir, L.P. completed its process of integrating ESG topics into its strategic planning. ESG priorities were identified in collaboration with its stakeholders and a roadmap was established. Énergir, L.P. will continue to implement the concrete actions of its ESG approach in fiscal year 2023.

Énergir, L.P. also publishes the two following documents to account for its ESG activities.

Since 2021, Énergir, L.P. also published an annual Climate Resiliency Report, which is prepared in line with the framework prescribed by the TCFD. This report presents the climate-related risks and opportunities specific to Énergir, L.P. and its main subsidiaries, as well as climate-related strategy, governance and risk management. It also provides an assessment of the business model's resilience. Énergir, L.P. expects to publish is next Climate Resiliency Report in the second quarter of fiscal year 2023.

In addition, since 2013, Énergir, L.P. has published three sustainable development reports based on the guidelines set out in the Global Reporting Initiative. The financial and extra-financial indicators presented in these reports address the priority economic, social, environmental and governance concerns identified by Énergir, L.P.'s internal and external stakeholders. These indicators are published annually on a tracking platform available at www.energir.com.

No element relating to the sustainability performance, including the sustainability report and the Climate Resiliency Report, has been incorporated herein.

f) Legislative Framework

Federal

In April 2021, the Government of Canada announced its commitment to reduce its GHG emissions by 40 to 45.0% below 2005 levels by 2030. This is the context in which the *Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050* was assented to on June 29, 2021. Pursuant to this law, Canada's Minister of the Environment must set national targets for the reduction of GHG emissions for 2035, 2040 and 2045 to achieve carbon neutrality in 2050. These targets must be set no later than by December 1, 2024, 2029 and 2034, respectively.

This is the context in which the federal government adopted, in June of 2022, the *Clean Fuel Regulations* requiring gasoline and diesel producers and importers to lower the carbon intensity of the gasoline and diesel they produce or import into Canada by 3.5 grams of CO_2 eq. per megajoule in 2023 compared to 2016 levels, and 14 grams by 2030. Although gaseous fuels (including natural gas) were initially supposed to be subject to the regulations, the latter do not provide for an obligation to lower the carbon intensity of natural gas across its lifecycle. Énergir, L.P. is therefore not subject to these regulations. This standard complements the *Greenhouse Gas Pollution Pricing Act*, which does not apply to Quebec because the province has adopted a CATS, as described at greater length in Item 4.1.1.5 f) i. *Cap-and-Trade System for Greenhouse Gas Emission Allowances (CATS).*

Concurrently with the development and implementation of the *Clean Fuel Regulations*, the Government of Canada is taking additional measures to reduce GHG emissions or fight against climate change. Consequently, under the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream

Oil and Gas Sector), some of Énergir, L.P.'s facilities are, among other things, required to comply with standards governing the quantity of methane released into the atmosphere in the course of its activities and will be subject to three annual leak detection inspections. These new requirements came into force progressively starting on January 1, 2020.

To date, and subject to the above, there are no other federal regulations compelling Énergir, L.P. to reduce its GHG emissions.

Provincial

i. Cap-and-Trade System for Greenhouse Gas Emission Allowances (CATS)

The Government of Quebec implemented CATS which, since January 1, 2014, is connected with California's cap-and-trade system for greenhouse gas emission allowances.

As such, Énergir, L.P.:

(1) is required to report to the Ministry of Environment (i) its own GHG emissions; (ii) fugitive GHG emissions and GHG emissions caused by damage; and (iii) the GHG emissions of its customers (other than those customers that are themselves emitters subject to the CATS, that are attributable to the use or combustion of natural gas for their establishments covered by the system) resulting from the use or combustion of the natural gas distributed by Énergir, L.P.;

(2) is required to have an independent ISO 14065-accredited auditor verify annually its GHG emissions, fugitive GHG emissions, emissions caused by damage and the GHG emissions of its aforementioned customers pursuant to the ISO 17011 program;

(3) is required to cover the GHG emissions verified by its auditor.

The CATS is subject to a compliance period of three years, with the exception of the first such period which was two years. Therefore, the fourth CATS compliance period began on January 1, 2021 and will end on December 31, 2023. No later than by November 1 after the end of each relevant compliance period, every entity subject to the CATS must have at least as many emission allowances in its compliance account as its GHG emissions verified by the independent auditor (as indicated above) during the compliance period in question.

ii. Duties

The *Act respecting Transition énergétique Québec* provided that every energy distributor (including Énergir, L.P.) must pay an annual contribution to the TEQ to finance its activities, namely the programs and measures necessary to achieve the energy targets defined by the Quebec Government. Under the Regulation respecting the annual share payable to Energy Transition Quebec, the annual contribution is payable in four instalments, on March 31, June 30, September 30 and December 31 of each year. The contribution paid by Énergir, L.P. during fiscal year 2022 was $15,765,250, compared to $15,768,337[9] for fiscal year 2021.

As explained above under Item 4.1.1.3 a) *Normalized Deliveries*, under the *Act mainly to ensure effective governance of the fight against climate change and to promote electrification*, the annual share described above is maintained but must now be paid to the Ministère de l'Énergie et des Ressources naturelles.

In fiscal year 2022, the environmental protection requirements did not have any material financial or operational impact on (i) Énergir, L.P.'s property, plant and equipment acquisitions, (ii) Énergir, L.P.'s consolidated net income and (iii) Énergir, L.P.'s competitive position, with the exception, in particular, of the impact of the coming into force of the CATS, which affected the competitive position, as previously described under this item. However, the costs associated with the environmental protection requirements cannot be easily identified separately as they are embedded in Énergir, L.P.'s system maintenance and development programs. Except for the CATS and the related compliance costs, as described under this item, in Management's view, the environmental protection requirements will not have any material financial or operational impacts in fiscal year 2023.

[9] The amounts are set by orders-in-council of the Government of Quebec.

4.1.1.6 Climate Change

a) Climate Change Risks and Opportunities

To structure its understanding of the risks and opportunities related to climate change based on the recommendations of the TCFD, Énergir, L.P., Green Mountain and Vermont Gas use a common methodology. The table below therefore presents these risks and opportunities for Énergir, L.P., Green Mountain and Vermont Gas, and specifies how they would manifest themselves and what the potential financial repercussions would be.

The following table presents the physical and transitional risks relating to climate change. Please note that in this table, the electricity-related risks apply solely to Green Mountain, and that the gas-related risks apply solely to Énergir, L.P. and Vermont Gas.

Risks			Potential Financial Impacts	Opportunities
Transition Risks	**Political and legal**	▪ Increase in the Price of Carbon; ▪ More aggressive decarbonization goals; ▪ More restrictive regulation of existing products and services; ▪ Inconsistency between the regulatory framework and business objectives; ▪ Exposure to GHG emissions litigation or non-compliance with GHG emission reduction regulations.	▪ Increase in service costs (implementation of specific measures to reduce the carbon footprint) reflected in customers' rates; ▪ Decrease in demand for fossil natural gas, resulting in particular from increased compliance costs (e.g.: CATS).	▪ Increased demand for RNG and energy services; ▪ Increased demand for the responsible procurement of natural gas; ▪ Policies, regulations and financing conducive to RNG and hydrogen development; ▪ Injection of green hydrogen in the gas network; ▪ Diversification of renewable energy sources; ▪ Energy efficiency in offices, electrification of certain vehicle fleets, reduction at the source, re-use, recycle and repurpose of resources used; ▪ Achievement of the 100% renewable supply targets (Green Mountain 2030 target); ▪ Reduction of emissions with a renewable electricity supply.
	Technological	▪ Lesser efficiency of natural gas technologies compared to alternative energy solutions; ▪ Technological advances that facilitate decarbonization for customers; ▪ Unsuccessful investments in new technology.	▪ Decrease in demand for fossil natural gas (resulting from the use of comparatively more efficient equipment, electrotechnology and storage); ▪ Stranded investment costs in technologies that do not favour the achievement of our objectives.	▪ Development of complementary energy services (energy expertise, storage assets, fuel, green hydrogen); ▪ Increase in the offer of energy efficiency programs; ▪ New clean technologies to decarbonize the energy delivered.
	Market-related	▪ Change in customer behaviour that favours energy sources with lower GHG emissions; ▪ Increase in supply cost.	▪ Decrease in demand for fossil natural gas; ▪ Lower share on certain markets that could have an impact on the distribution of revenues from Énergir, L.P.	▪ Dual energy offer for Quebec customers; ▪ Diversification of renewable energy sources including solar energy from sites of varied sizes (from residential rooftops to those of larger sites); ▪ Sharing program for peak electricity periods with customers.

Risks			Potential Financial Impacts	Opportunities
	Reputational	▪ Change in customer behaviour towards energy sources with lower GHG emissions; ▪ Increased stakeholder concern about GHG emissions.	▪ Reduced or more difficult access to financing (resulting from the consideration of environmental (including GHG emissions), social and societal criteria in the financing of projects or businesses); ▪ Decrease in demand for fossil natural gas.	▪ Greater demand for Énergir, L.P.'s carbon-neutral solutions.
Physical risks *(for more on this, please refer to the sub-section below, Physical Risks.)*	**Acute**	▪ Increased severity of extreme weather events (floods, landslides, freeze/ thaw cycles).	▪ Lower revenues relating to a decreased energy distribution capacity (resulting, for example, from breaks in the supply chain); ▪ Increased operating costs (maintenance and repairs, including labour, equipment and potential environmental damage, insurance premiums and costs related to the negative impacts on the workforce); ▪ Increase in required investments (more resilient construction or more frequent repairs); ▪ Reduced insurability of assets located in "high risk" areas; ▪ Changes in demand due to milder winters and hotter summers.	▪ Investment in network resilience projects; ▪ Recognition of the added value of carbon-neutral gas assets owing to their resiliency to climate changes.
	Chronic	▪ Changes in precipitation patterns and extreme variations in meteorological profiles; ▪ Rise in average temperatures.		

Physical Risks

The physical risks have a different influence depending on the nature of the activities. Indeed, electricity production and distribution activities, which rely on assets that are mostly above ground, are more sensitive than gas distribution activity to the variability and intensity of storms, forest fires, variability in precipitation thus affecting maintenance or production costs. Green Mountain's wind production is more widely influenced by wind strength and its solar production is dependent on intensity and periods of sunshine.

The impact of climate change can also have an impact on consumption profiles with greater demand for electricity in summer depending on the demand for air conditioning, for example.

The gas network, which is mostly underground, can be more significantly impacted by landslides or floods and consumption can also be influenced by climate change. Indeed, the decrease in cold periods can reduce the volumes distributed. Énergir, L.P. remains proactive in ensuring the resilience of its networks.

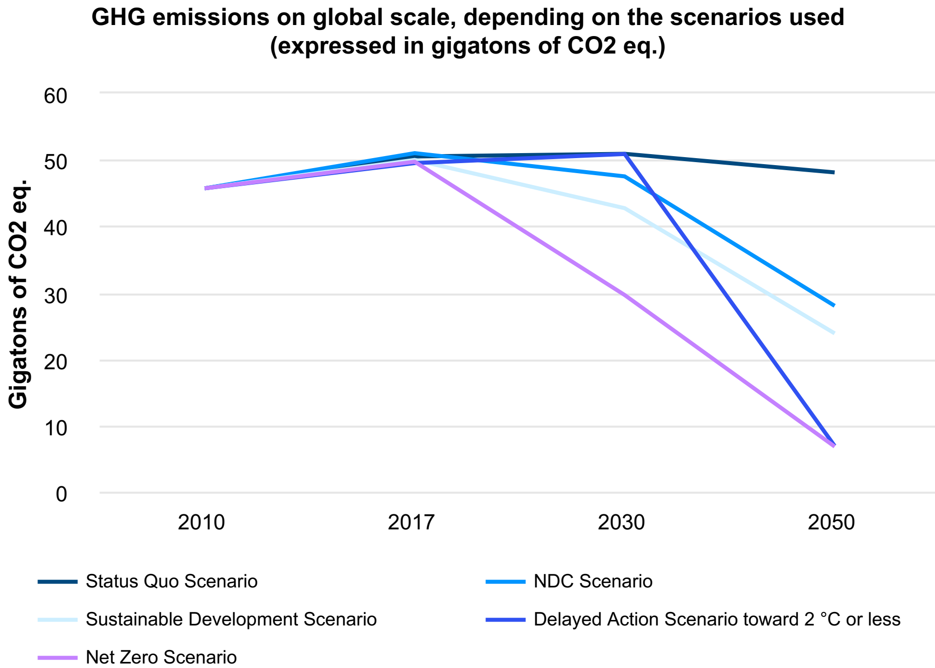
In 2022, Énergir, L.P., Green Mountain and Vermont Gas launched a thought process to assess how sensitive their assets are to various climate change scenarios. They are currently considering a process for identifying and assessing climate risks, and responding thereto over a long-term time horizon to reduce their assets' exposure to the effects of climate change and identify which effects will have the greatest impact on their assets. This exercise comes in the wake of the summary assessment of physical risks presented above.

b) GHG Emissions Scenarios for Horizons 2030 and 2050

i. Global Scenarios

In order to better assess the potential impact of the climate change risks and opportunities (described more fully under Item 4.1.1.6 a) *Climate Change Risks and Opportunities*) on the resiliency of Énergir, L.P.'s business model and over short term, medium term and long term timelines, Énergir, L.P. relied, in line with TCFD recommendations, on five quantitative scenarios from independent agencies that predict several possible global GHG emission pathways in the 2030-2050 timeframe. The use of these scenarios allows Énergir, L.P., Green Mountain and Vermont Gas to analyze the impacts of climate change on the resilience of the business models over different time horizons. The scenarios used are not GHG emissions forecasts. They represent a range of possible futures with respect to GHG emissions. While other scenarios are available or forthcoming, the scenarios used in this Annual Information Form have the advantage of proposing a range of possible futures that are for the most part distinct from each other.

These scenarios are described below.



Status Quo Scenario[10]

The Status Quo Scenario represents a future where few actions are taken to limit global warming. The physical risks for this scenario are greater than for other scenarios described below in the second half of this century, as no additional measures are taken to reduce GHG emissions.

NDC Scenario

The NDCs embody the commitments of each Paris Agreement signatory country,[11] to reduce their national GHG emissions and adapt to the effects of climate change. Every five years, each signatory country must establish, disclose and update the successive NDCs it plans to make at the national level. As a signatory of the Paris Agreement, Canada has submitted an NDC plan that came into effect in 2016. The NDC plan was subsequently revised in 2017, and in 2021. The United States submitted an NDC plan in April 2021. This scenario is therefore evolving in line with the new NDCs announced by various countries over time.

Since the scenarios were last scaled for fiscal year 2021, the Climate Action Tracker's[12] NDC curve shows a 23% drop in emissions for 2050 compared to that previously used.[13] Consequently, the pathway of the NDC Scenario is becoming more and more similar to the Sustainable Development Scenario. The GHG emission levels for 2030, however, remain unchanged. What is more, the NDC Scenario published in the 2021 Annual Information Form already reflected the new NDCs for Canada and the United States announced alongside the COP 26 meeting held at the end of calendar year 2021.

Sustainable Development Scenario

The Sustainable Development Scenario represents a stabilization of energy demand whilst maintaining economic and population growth. This stabilization is supported by significant and internationally coordinated efforts to boost energy efficiency and shift away from fossil fuels for energy production. The substitution of fossil fuels and the

(10) Bank of Canada - Scenario Analysis and the Economic and Financial Risks from Climate Change: https://www.bankofcanada.ca/2020/05/staff-discussion-paper-2020-3/?page_moved=1
(11) Among other things, this agreement seeks to limit any rise in the planet's average temperature way under 2 °C compared to pre-industrial levels, and to continue taking action to limit the rise in temperature to 1.5 °C compared to pre-industrial levels. This agreement came into effect on November 4, 2016.
(12) The Climate Action Tracker is an independent scientific analysis that tracks climate actions taken by governments and measures them against the target provided for in the Paris Agreement to limit warming to well under 2°C and pursue efforts to limit warming to 1.5°C. This analysis is performed by Climate Analytics, a non-profit climate science and policy institution based in Berlin, Germany.
(13) Global emissions under the NDC Scenario, Climate Action Tracker.

sustained decarbonization efforts in this scenario are consistent with a world where global warming is limited to 2°C or less compared to preindustrial levels.

Delayed Action Scenario

The Delayed Action Scenario represents a future where countries fail to meet their NDC commitments between 2020 and 2030, and then take more stringent mitigation measures to limit warming to 2°C or less compared to preindustrial levels. Measures are delayed until 2030 and require significant catch-up between 2030 and 2050. As a result, GHG reductions after 2030 and the associated transition risks are much greater.

Net Zero Scenario

The Net Zero Scenario represents a transformation of the global energy system to achieve global carbon neutrality by 2050 and limits the global temperature rise to 1.5°C or less compared to the pre-industrial era. It also assumes continued economic growth.

In this scenario, declining final energy demand, the rapid deployment of more energy-efficient technologies, electrification and the rapid growth of renewables play a central role in reducing GHG emissions across all sectors. Emerging fuels and technologies, such as hydrogen and hydrogen-based fuels, bioenergy and carbon capture and storage, also play a major role, especially in sectors where emissions are often the most difficult to abate. This scenario excludes any new oil or gas fields beyond the projects already approved at the time the Net Zero Emissions by 2050 Scenario was published by the International Energy Agency in May 2021.

This Annual Information Form presents an emissions pathway for the Net Zero Scenario that is virtually unchanged, though modifications have been made to this scenario's underlying assumptions. The main changes to the assumptions compared to those of the Net Zero Scenario published in the 2021 Annual Information Form are:

- An additional 10% and 15% reduction by 2030 and 2050, respectively, in the global consumption of natural gas compared to 2020;
- A drop of approximately 20% in carbon emissions captured and removed from the atmosphere in 2030 and 2050 (capture and sequestration of bioenergy emissions and direct air capture); and
- Continued investment in existing fossil energy projects to meet demand up to the 2030 horizon, but without new traditional investments. The assumption in 2021 only presumed that no new investment in conventional fossil fuels would be necessary.

The current and announced policies so far do not allow the realization of the Net Zero Scenario.

ii. Quebec-Wide Scenarios

To ensure that its Vision 2030-2050 enables its resiliency by 2050, Énergir, L.P. used the scenarios presented under Item 4.1.1.6 b) i. *Global Scenarios* above, having scaled them to the province of Quebec. Quebec has its own policies and regulations and has made political commitments to combat climate change that influence possible future pathways for GHG emissions.

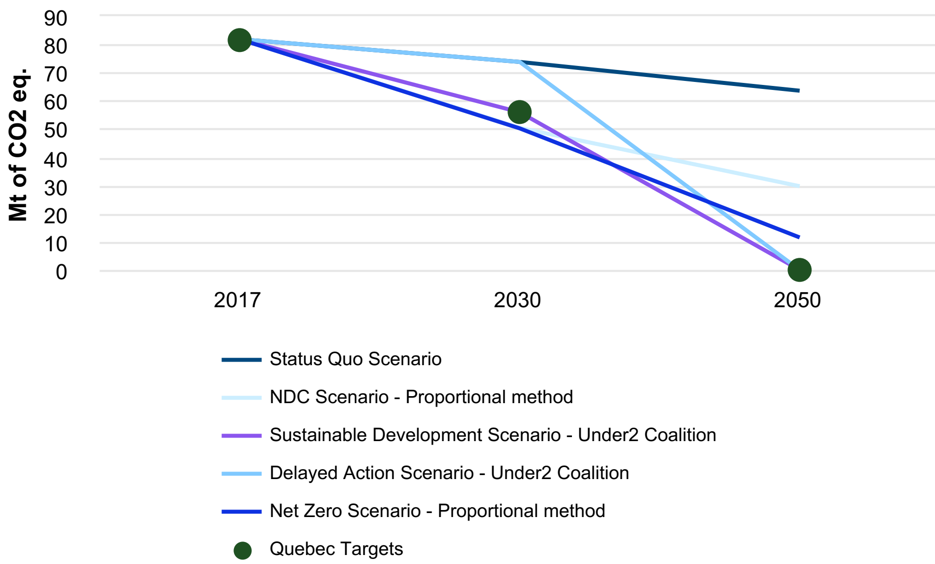
Énergir, L.P. used the Under2 Coalition methodology[14] where applicable and, in other cases, the proportional method to adapt the scenarios to the Quebec context.[15] Once this scale is carried out, the GHG reduction pathways in these scenarios become more significant for Quebec. This methodology is relevant for Quebec as it is a member of the Under2 Coalition. The proportional methodology is also relevant for Quebec when the Under2 Coalition methodology cannot be applied. Indeed, the proportional methodology consists in transposing the percentage of emission reductions at the global level to Quebec.[16]

The exercise of scaling global GHG emission reduction pathways to apply to Quebec reveals that the pathway of the NDC Scenario, when adapted to the Quebec context using the proportional methodology, will now reach nearly 30 million tonnes of CO_2 equivalent by 2050 (compared to nearly 40 million tonnes of CO_2 equivalent in the 2021 Annual Information Form). The 2030 pathway remains unchanged.

(14) The Under2 Coalition became the Net Zero Coalition on October 19, 2021. As of December 16, 2021, Quebec had not revised its targets based on the Memorandum of Understanding revised by this coalition.
(15) This methodology is based on achieving the target of limiting global warming to 2° Celsius or less by 2100 from pre-industrial levels and reducing GHG emissions by one percentage compared to the 1990 levels in each jurisdiction by 2050. This methodology is therefore not applicable to scenarios that do not limit global warming to 2 degrees Celsius or less by 2100 from pre-industrial levels.
(16) For example, under this methodology, 20% of global emission reductions scaled up at the Quebec and Vermont levels represents a 20% reduction in emissions in Quebec, and 20% in Vermont. This methodology is therefore not applicable to scenarios that do not limit global warming to 2 degrees Celsius or less by 2100 from pre-industrial levels.

The following graph therefore presents the possible GHG emission pathways according to the scenarios used as they apply to Quebec. It also presents Quebec's targets in 2030 and 2050.

Possible annual GHG emission pathways according to the scenarios used as they apply to Quebec (expressed in million tonnes of CO2 eq.)



(a) The scenarios used for Status Quo Scenario come from reports produced by Dunsky Energy Consulting for Quebec and Vermont, and are based on a modelling of the NATEM-Canada optimization model in the case of Quebec, and an earlier version of a similar modelling for Vermont. These scenarios have been developed across jurisdictions of interest, so no scaling is required.

(b) For scenarios scaled according to the Under2 Coalition methodology, the methodologies for Quebec and Vermont were harmonized to facilitate understanding. This is why the Sustainable Development Scenario curve reaches net zero emissions in 2050.

If Quebec were to align itself with a GHG emissions pathway that limits the rise in global temperatures to 1.5°C, it would have to reduce its GHG emissions by at least about an additional 5 million tonnes of CO_2 eq. than the reduction anticipated by 2030. In addition, some scenarios do not succeed in reducing all GHG emissions in 2050. For example, the assumptions of the Net Zero Scenario indicate that there would remain a small share of fossil natural gas for certain uses that are more difficult to decarbonize in Quebec's energy mix in 2050. Quebec could still achieve carbon neutrality if it consistently commits to such a pathway, first by reducing energy consumption and then by integrating more renewable energies and finally by offsetting residual emissions.

All the scenarios predict a reduction in GHG emissions and therefore a reduction in the use of more GHG emitting energy sources over the 2030 and 2050 horizons. This would necessarily lead to a transformation of the markets Énergir, L.P. serves. However, the speed and intensity of GHG emission reductions vary from scenario to scenario, and Énergir, L.P. will need to remain vigilant regarding the evolution of possible scenarios in how they present future GHG emission pathways.

As mentioned in Item 4.1.1.6 b) i. *Global Scenarios* above, these scenarios are not projections but are used to analyze Énergir, L.P.'s risks and opportunities related to climate change from different angles.

Scenarios	Description of the impacts on Énergir, L.P.
Status Quo	Growth in the natural gas volume distributed by Énergir would continue past 2030. The increase in global temperatures could reach 3.6°C. It is therefore expected that climate change would further affect Énergir, L.P.'s physical assets.
NDC	Compliance with GHG emission reduction policies and achievement of GHG emission reduction targets would result in significant changes to Énergir, L.P.'s traditional business model. Some of Énergir, L.P.'s markets are expected to be significantly impacted, specifically the building heating market, where lower GHG emitting alternatives are available. Because the physical impacts of climate change over the next decade are driven by past emissions, some of the physical effects of climate change would be felt without reaching the significant impacts of the *Status Quo* Scenario. A global warming above 2°C is nevertheless expected to result in significant physical impacts.
Sustainable Development and Delayed Action	The physical impacts of climate change would be the same for these two scenarios, but they are expected to affect Énergir, L.P. at different times and in a more or less significant way. Énergir, L.P. should therefore be less affected by the physical impacts of climate change after 2040. In the Sustainable Development Scenario, the energy transition would already be underway and continuing gradually through to the 2030 and 2050 horizons. In this scenario, Énergir, L.P. would have to continuously deal with sustained transition risks. Note that Quebec's targets are aligned with the pathway presented in this scenario. In the Delayed Action Scenario, the possibility of a shock (an abrupt change in policies after 2030 affecting Énergir, L.P. directly or the operations of its customers) is foreseeable. In this case, the adaptation of Énergir, L.P.'s business model in order to manage the risks associated with this transition could represent a significant challenge. These scenarios are consistent with limiting the temperature rise to 2ºC or less by 2100 compared to pre-industrial levels.
Net Zero	Énergir, L.P. will have to deal continuously with sustained short-term transition risks. While the decarbonization effort will be major for all sectors of the economy by 2030 to limit temperature to 1.5°C compared to the pre-industrial era, this scenario imposes increased transition risks for Énergir, L.P. but creates conditions conducive to the implementation of its decarbonization solutions. Despite limiting temperature increases, physical risks are still expected, but are mitigated by prompt and concerted action. The current and announced policies so far do not allow the realization of the Net Zero Scenario.

c) Resiliency of Énergir, L.P.'s Business Model

To address climate risks and opportunities, as more fully described under Item 4.1.1.6 a) *Climate Change Risks and Opportunities*, Énergir, L.P. announced its Vision 2030-2050 in the fall of 2020, which aims to enable it to make the energy distributed to its customers carbon neutral by 2050.

To achieve this, Énergir, L.P.'s Vision 2030-2050 primarily targets, by the 2030 horizon, the GHG emissions of its customers that come from the use of natural gas for the heating of air and water in the buildings sector (residential, commercial and institutional markets).

Vision 2030-2050 is based on the four following orientations:[17]

(1) Accelerating the growth of long-term energy efficiency efforts

Énergir, L.P. intends to accelerate the growth of energy efficiency efforts. It has set itself the target of helping its customers, through its various energy efficiency programs (as described more in detail under Item 4.1.1.3 a) *Normalized Deliveries*), achieve a cumulative reduction of one million tonnes of CO_2 eq. between 2020 and 2030.[18]

Énergir, L.P. aims to maintain this accelerated pace between 2030 and 2050, despite the fact that achieving this target could become progressively more difficult. To this end, Énergir, L.P. should be launching several strategies to

[17] In the 2020 Annual Information Form, Vision 2030-2050 presented a fifth initiative: continue to replace more polluting energy with natural gas in the industrial sector. This initiative, however, should have been included in the fourth initiative, namely: diversify Énergir, L.P.'s activities to foster new growth drivers.

[18] This target covers the period from October 1, 2020 to September 30, 2030, and covers all of the markets served by Énergir, L.P. and takes into account the contribution of its Energy Efficiency Programs.

enhance its current offering while promoting new and increasingly efficient technologies and digital intelligence. To do so, it is developing marketing strategies and communication campaigns to maximize customer participation in its energy efficiency programs and offer new energy services.

(2) Thanks to new marketing approaches, ensure that the RNG's share rapidly increases to at least 10% of its customers' consumption by 2030

Énergir, L.P. aims to deliver increasingly more RNG to its customers annually. Its goal is for RNG to represent at least 10% of the annual volume it delivers for consumption by 2030, which in terms of today's volume would equate to about 567 million m^3 and an annual GHG emission reduction of 1 million tonnes of CO_2 eq. In the longer term, the technical and economic potential of RNG production in Quebec could be even greater with the possible arrival of new technologies, such as methanation.[19]

In the course of its fiscal year 2022, Énergir, L.P. launched the commercial offering of voluntary RNG consumption to its business and residential customers. This key step in the deployment of Énergir, L.P.'s decarbonization strategy should accelerate voluntary RNG consumption among its customers and therefore minimize the rate impact associated with achieving the regulatory targets for the volume of RNG to be delivered.

(3) Develop a strong complementarity with electricity

Electricity will play a key role in decarbonizing Quebec's economy, including in the building sector by 2030. However, the conversion of hydrocarbon uses in Quebec to electricity presents significant challenges. Hydro-Quebec, Quebec's electricity distributor, is forecasting a power deficit[20] in the coming years because of increased demand from the electrification of transportation and the conversion of other uses currently employing petroleum products. Specifically, this electrification could significantly increase Hydro-Québec's peak demand, which could entail significant costs in electrical infrastructure to meet this demand of a few hundred hours per year and would greatly increase the societal cost of decarbonization.

Therefore, complementarity between Hydro-Québec's electricity network and Énergir, L.P.'s gas network would see a portion of natural gas uses being electrified in the residential, commercial and institutional market segments, while natural gas and RNG would be used during peak electricity use periods, occurring during the year's cold spells, reducing buildings' carbon footprint in a much more cost-effective way in Quebec.

In this context, in fiscal year 2021, Énergir, L.P. entered into, with Hydro-Québec, an agreement for the establishment of a joint and coordinated dual-energy approach.

In September 2021, Énergir, L.P. and Hydro-Québec jointly filed an application before the Régie for its approval in order to implement this agreement with respect to the matters under its jurisdiction. In a May 2022 decision, the Régie approved Hydro-Québec and Énergir, L.P.'s joint request to offer a shared dual-energy electricity-natural gas solution to existing natural gas customers in the residential sector. It provides that Hydro-Québec will pay Énergir, L.P. a GHG contribution recognizing the gas network's value during winter peak demand periods. The Régie decision acknowledges that it is in the public interest that regulated entities assume their responsibilities by contributing to the economy's decarbonization in a context of climate crisis. An application to review this Régie decision has been filed. With dual energy, the two leading energy distributors will therefore work to considerably reduce the natural gas consumption (and, consequently, GHG emissions) of over 100,000 customers currently using natural gas for heating purposes by 2030. The distributors will also offer all Énergir, L.P. customers, including new buildings, a zero-emission solution thanks to dual-energy electricity-renewable natural gas. The dual-energy project is counting on a pragmatic approach that could help save Quebec society considerable amounts of money while accelerating the decarbonization of heating buildings. By 2030, this solution should save close to $1.7 billion compared to the full electrification of the markets targeted, limit the impacts on rates for the customers of both distributors, and eliminate up to 540,000 tonnes of GHG emissions.

An application to offer dual energy to the commercial and institutional sectors was filed before the Régie in October 2022. If the Régie approves the application, dual energy may be available to customers in these sectors as early as the summer of 2023.

The Government of Quebec has expressed its support for this initiative by issuing an order in council respecting the economic, social and environmental concerns in which it emphasizes the project's importance in achieving the

[19] Methanation is the reaction of carbon monoxide or carbon dioxide with hydrogen in the presence of a catalyst to produce methane (https://www.afgaz.fr/sites/default/files/u3/methanation.pdf. https ://www.afgaz.fr/sites/default/files/u3/methanation.pdf).

[20] Hydro-Quebec: Supply Plan 2020-2029 (http://publicsde.regie-energie.qc.ca/projets/529/DocPrj/R-4110-2019-B-0005-Demande-Piece-2019_11_01.pdf).

targets of the 2030 Plan for a Green Economy. This plan allocates a budget of $125 million to support customers and fund initiatives designed to achieve an optimal complementarity of the electricity and gas networks.

(4) Diversify Énergir, L.P.'s activities to foster new sustainable growth drivers

The diversification of its operations in Quebec would also allow Énergir, L.P. to achieve medium- and long-term growth. For example, Énergir, L.P. is currently evaluating certain opportunities in the development of district energy loops, as well as the expansion of services offered to customers, particularly in terms of optimizing its energy consumption. In addition, diversification could also take the form of more upstream involvement in the RNG sector, through the intermediary of an Énergir, L.P. affiliate, as well as in the development of the green hydrogen sector as a source of energy supply.

Resilience of Énergir, L.P.'s Business Model

In achieving the four initiatives, Énergir, L.P.’s Vision 2030-2050 is consistent with a GHG emission reduction pathway as provided for in the Sustainable Development Scenario, which is aligned with the Government of Quebec’s targets. This pathway should help limit global warming to 2^{o}C. To aim for a more ambitious pathway that would limit global warming to 1.5^{o}C, new initiatives will need to be deployed, especially with Énergir, L.P.’s major industrial customers whose decarbonization strategies require specialized support.

Consequently, this pathway would ensure the viability of the business model by focusing on value creation rather than on the volume of natural gas distributed, while the quantities of natural gas distributed could be maintained or slightly reduced by 2030 and then decrease more markedly by the 2050 horizon. At the same time, the increasing volumes of RNG distributed by 2050 would reduce exposure to higher carbon taxation.

Ensuring the resilience of Énergir, L.P.’s business model will be a complex task. The business model will have to ensure that it maintains competitive rates and preserves revenues and profits, at a time when the volumes distributed are expected to decrease and the integration of new sources of renewable energy will be more expensive. Énergir, L.P. is confident that its Vision 2030-2050 and its related initiatives will ensure this resilience.

The update in fiscal year 2022 reveals slight variations in the buildings sector, i.e. for typical cases in the residential, commercial and institutional markets. Several elements are considered when calculating a competitive position’s evolution, especially the evolution of cost of service, including the Price of Carbon under the regulations in effect at the time of this calculation. These elements are updated on an ongoing basis. These projections show that the energy solutions Énergir, L.P. offers remain globally competitive even though the economic advantage will deteriorate over time due to electrification.

The measures to ensure Énergir, L.P.'s resilience by 2050 are based mainly on the following premises:

1. In most markets, Énergir, L.P. expects that until 2050, RNG will remain competitive with respect to electricity. RNG, moreover, is still less expensive from a societal point of view than several electricity solutions: RNG draws its main value from being interchangeable with fossil natural gas, which means existing infrastructures can be upgraded and offer the same flexibility to meet Quebec’s demanding seasonal needs. Moreover, RNG is a low-impact option that allows Énergir, L.P.’s customers to decarbonize their activities without requiring modifications or investments.

2. Fossil natural gas has a significant competitive advantage and should remain stable in the Industrial Market until 2050, giving Énergir, L.P. enough flexibility to integrate more decarbonization opportunities. Note that energy bills are one of the financial elements taken into consideration by industrial customers, as switching from natural gas to electrical processes requires considerable investments, if such a switch is technically possible.

3. The reduction in revenues associated with the estimated decrease in the natural gas volume distributed in 2050 could be offset by initiatives that allow Énergir, L.P. to maintain its revenues, such as support for energy efficiency or the implementation of the joint dual-energy program with Hydro-Québec, as these two actions are more fully described above.

Maintaining Énergir, L.P.'s competitive position is indeed important. A decrease in the distributed volume coupled with an increase in costs (Price of Carbon, integration of renewable energy sources) induces upward pressure on rates. To limit this pressure over time and maintain a competitive energy supply, Énergir, L.P. must therefore focus on value-added activities. Maintaining a competitive energy supply is an essential element of Énergir, L.P.'s business model. Indeed, natural gas distribution activities in Quebec are regulated. The profit generated by Énergir, L.P.

depends on the net value of its assets (its rate base) as well as the rate of return authorized by the Régie. Like operating costs, profit is authorized annually during the presentation of the rate case to the Régie and recovered through Énergir, L.P.'s rates, as described at greater length in Item 4.1.1.1. a) *Regulatory Process*. Rates that remain competitive in the majority of the target markets significantly limit the risk of not recovering invested capital and the associated return in the medium and long term.

For the energy that Énergir, L.P. distributes to achieve carbon neutrality by 2050, additional solutions to those presented in Vision 2030-2050 will be needed. During fiscal year 2023, Énergir, L.P. intends to continue working to refine its decarbonization roadmap and further align its strategy with a pathway compatible with limiting temperature rise to 1.5°C and less.

d) Climate Change Risk Identification and Management Practices

In this section, information on the risks and opportunities related to climate change is presented from a group perspective.

Aware of their exposure to the climate change risks described in greater detail under Item 4.1.1.6 a) *Climate Change Risks and Opportunities*, Énergir, L.P., Green Mountain and Vermont Gas have adopted a risk governance framework to facilitate the achievement of business objectives and strategies while favouring an organizational culture committed to managing risks in a proactive and efficient way. Risks are an integral part of the activities and decisions of Énergir, L.P. and its subsidiaries.

The existing integrated risk management process includes risks related to climate change. Indeed, the process to identify, assess and manage climate risks is integrated into the business risk management process and asset management processes.

Énergir, L.P., Green Mountain and Vermont Gas have implemented risk assessment methodologies that consider the probability of occurrence and potential impact of each risk. The controls in place and mitigation measures are considered, and management ensures that the risks are prioritized and addressed according to their relative impact.

Through a consolidated dashboard that takes into account the activities of Energir, L.P., Green Mountain Power and Vermont Gas, major risks are presented semi-annually to the Management Committee, the Audit Committee and the Board.

4.1.1.7 Governance as it relates to Climate Change

Énergir, L.P.’s governance reflects its commitment to contribute to and support efforts to counter the impacts of climate change.

Risks and opportunities related to climate change are monitored by the Board and by Management. The Board oversees the management of Énergir, L.P.’s activities to ensure, among other things, the company’s financial health and resilience over the short, medium and long term. More specifically, it ensures that Management adopts a strategic planning process and periodically implements a strategic plan that addresses business opportunities and risks, among other things. It also ensures that Énergir, L.P.’s corporate strategy, including strategic orientations stemming from climate change issues, is deployed. It identifies and monitors Énergir, L.P.’s main risks and ensures the implementation of appropriate measures and management systems for such risks.

In fiscal year 2022, the Board was supported by the following committees, which jointly oversaw the effectiveness of Énergir, L.P.’s strategies and performance with respect to climate change risks and opportunities: the OHS-Env. Committee, the Audit Committee, and the HR-CG Committee.

Reporting on climate-related risks and opportunities to the Board
The OHS-Env. Committee was responsible, among other things, for the climate change component. It received periodic reports from Management in this regard, including a follow-up report on the achievement of GHG reduction targets. As part of the preparation of the Climate Resiliency Report, this committee examined the action plan in this regard and discussed with Management the initiatives that Énergir, L.P. proposed for the fiscal year in order to pursue its climate ambition. It also made its recommendations to the Board for approval of the report. On the other hand, this committee monitored the implementation of Énergir, L.P.'s Environmental Policy.
The Audit Committee ensured that Management took appropriate steps to identify financial risks that could affect Énergir, L.P., including those stemming from climate change, and that it implemented sufficient measures to manage those risks.
The HR-CG Committee developed Énergir, L.P.'s corporate governance approach, including the governance regarding overseeing climate-related risks and opportunities, as well as practices and procedures for applying this approach.

Following the October 18, 2022, and December 15, 2022, changes to the Board's mandate, as described at greater length in Item 10.2.1.1. *Board of Directors*, the Board's mandate now explicitly indicates the Board's oversight responsibilities where ESG factors and corporate risks are concerned.

Furthermore, following the changes to the structure of the Board committees made on October 18, 2022, the Board committees are: the CGEE Committee, the HR-SR Committee and the Audit Committee. In order to ensure that the members of these committees have the expertise and knowledge required to support the Board, a grid of the requisite profiles and expertise has been drawn up which includes environmental and climate change expertise. The main responsibilities of these Board committees, including environmental and climate change responsibilities, are described in Items 10.2.1.6 *Committees of the Board* and 10.2.2.1 *Relevant Education and Experience*.

On October 1, 2020, Énergir, L.P. amended its Long-Term Incentive Program for Executive Officers. The program, which tracks performance indicators, includes the following strategic indicator - the "Decarbonization effort - reduction of greenhouse gas (GHG) emissions." This indicator tracks GHG emission reductions in Quebec. For more information on this program, please refer to Item 10.1.3.7 *Long-Term Incentive Program.*

Énergir Inc.'s President and Chief Executive Officer manages Énergir, L.P.'s operations. He is ultimately responsible for strategic planning and ensuring that its initiatives cover risks and opportunities related to climate change. He is supported in his responsibilities related to Énergir's Affiliates by the Group Management Committee, which consists of certain members of Management as well as the presidents of Green Mountain Power and Vermont Gas. Under the leadership of the President and Chief Executive Officer of Énergir Inc., the Management Committee of Énergir, L.P. (in which all sectors of Énergir, L.P. are represented) has developed Vision 2030-2050 to guide Énergir, L.P.'s development. The vision's alignments are regularly reviewed to take into account in particular emerging and new trends and ensure that they remain relevant. The Management Committee has established a framework in order to identify, assess and manage the various risks inherent to the industry in which Énergir, L.P. operates, including those related to climate change. These elements are also addressed during the Group Management Committee meetings of the Énergir group.

Énergir, L.P. has adopted an internal governance structure that promotes the sound management of climate issues in establishing its objectives, strategies and actions across various levels of the organization. Thus, the offices of several vice presidents and the financial department support the Management Committee in its reporting to the Board and its committees. They are assisted by their respective teams, the Sustainable Development Strategy Committee and the collaborators of Énergir, L.P.'s various segments.

4.1.1.8 Development Projects

Additional information regarding Énergir, L.P.'s development projects in the area of natural gas distribution in Quebec can be found in section D) *Segment Results* on pages 18 to 21 of the 2022 MD&A.

4.1.2 Distribution of Electricity and Natural Gas in Vermont

Green Mountain, a wholly owned subsidiary of NNEEC, is the largest electricity distributor in the State of Vermont in the United States. Green Mountain generates, transports, distributes, purchases and sells electricity in Vermont and provides electric network construction services in that State. Green Mountain also transports electricity in the State of New Hampshire and generates electricity in relatively small quantities in the States of New York, Maine and Connecticut.

Vermont Gas, also a wholly owned subsidiary of NNEEC, is the sole gas distributor in the State of Vermont and provides other energy-related services, including increasing energy efficiency by renovating natural gas equipment.

4.1.2.1 Green Mountain

a) Regulatory Process and Rates

Green Mountain is regulated by the VPUC. Electricity rates are approved annually by the VPUC and are established using a cost-of-service method. For fiscal year 2022, an annual adjustment mechanism was in place to ensure that additional costs or savings, above a set limit (referred to as a "dead band") of US$307,000 plus 10% of costs or US$150,000 plus 10% of savings for certain power supply expenses as ordered by the VPUC, resulting from retail revenue and the electricity supply and transmission compared to forecasts are recovered from or returned to customers. In addition, according to the current regulatory framework, Green Mountain must also meet certain service quality performance indicators on a calendar year and quarterly basis. These indicators mainly address

- quality of service provided to customers and customer satisfaction;
- workplace safety; and
- system reliability.

If Green Mountain fails to meet its performance indicator thresholds, a monetary penalty may be imposed on Green Mountain.

Green Mountain's capital structure consisted of shareholder's equity of 50.4% in fiscal year 2022 and 49.9% in fiscal year 2021. Its allowed rate of return was 8.57% in fiscal year 2022 and 8.20% in fiscal year 2021.

i. Multi-Year Regulation Plan, Fiscal Years 2019- 2022

In May 2019, the VPUC approved Green Mountain's Multi-Year Regulation Plan (the "**MYR Plan**") effective October 1, 2019 through September 30, 2022. Under the MYR Plan, the traditional rate case filed on April 13, 2018, served as the base year for adjustments in fiscal years 2020-2022. The features of the MYR Plan were designed to best serve customers, provide stability, and addressed changes in the energy landscape and included, namely, the following:

- a projected, smoothed base rate for the three years of the MYR Plan, based on a three-year forecast of all costs. The projected, smoothed base rate was the projected average rate for each fiscal year in the MYR Plan. This rate was used to set the initial annual base rate for fiscal year 2020 and provided the projected rates for fiscal years 2021 and 2022. The second base rate filing was made on June 1, 2020 for fiscal year 2021, and the third base rate filing was made on June 1, 2021 for fiscal year 2022, which rates were subject to any annual adjustments authorized under the MYR Plan as described below;
- the non-power costs contained in the initial annual base rate filing for fiscal year 2020 were fixed for the term of the MYR Plan. The MYR Plan provided a revenue decoupling mechanism for electricity sales revenues, annual adjustments to Green Mountain's power supply costs, revenue forecasts, return allowed on shareholder's equity and associated ancillary impacts on income tax expense and gross revenue and fuel gross receipts tax. As a result of the revenue decoupling mechanism, revenue variances against the rate case were allowed to be recovered or returned to customers after a netting against variances in power supply costs, minus a dead band described above, and allowed major storm costs. These recoveries or returns were made in accordance with the quarterly smoothing mechanism approved by the VPUC;
- a three-part exogenous change adjustor designed to address the impact of climate change which has increased the severity and frequency of major storms, and other exogenous events. The first component of the exogenous change adjustor addressed non-storm exogenous events outside Green Mountain's control; the second component addressed major storm events that occurred during the term of the MYR Plan; and the third and final component of this adjustor addressed collection of prior major storm costs that were incurred prior to the inception of the MYR Plan, which allowed Green Mountain to collect US$8 million per year from customers as a separate line item surcharge to cover the approximately US$24 million of prior year major storm costs;
- a return allowed on shareholder's equity which adjusted annually, up or down, based on 50% of the change in the 10-year U.S. Treasury bond yield over a defined three-month period;
- continuation of the synergy savings plan and O&M platform provided for after the Merger and required until September 30, 2022;
- fixed capital spending over the three-year life of the MYR Plan with the ability to seek regulatory approval for limited exceptions;
- a mechanism for sharing with customers returns in excess of or short of the return allowed on shareholder's equity;

- an emerald ash borer adjustor to collect US$1.2 million annually as a separate line item on customer bills to proactively remove ash trees in power line corridors confirmed to have emerald ash borer infestations or are at high risk for infestation, separate from normal vegetation management due to the infestation emerging at the time the MYR Plan was approved;
- authorization for Green Mountain to seek approval of a climate plan ("**Climate Plan**") (which approval was obtained in fiscal year 2020, as further described below);
- continuation of Green Mountain's innovative pilot program and existing service quality and reliability performance monitoring and reporting requirements; and
- the filing of a traditional cost of service rate case no later than January 15, 2022 for rates for fiscal year 2023.

The interplay of the various components of the MYR Plan resulted in certain charges or credits for customers. Pursuant to the MYR Plan, Green Mountain annually applied for approval of its base rate filing.

On August 31, 2021, the VPUC approved Green Mountain's third and final annual base rate filing under the MYR Plan for fiscal year 2022, effective October 1, 2021, reflecting a 4.69% increase to base rates and an allowed rate of return on shareholder's equity of 8.57%.

ii. Multi-Year Regulation Plan, Fiscal Years 2023-2026

On September 1, 2021, Green Mountain filed for approval of its next Multi-Year Regulation Plan (the **"New MYR Plan**"). The New MYR Plan proposes to continue the framework for capital investments developed in the MYR Plan which allowed for flexibility in project planning and execution. The 10-year synergy savings plan and Operating and Maintenance ("**O&M**") platform originally approved during the Merger procedure and incorporated in the MYR Plan was completed in fiscal year 2022. For this reason, the New MYR Plan proposes a new methodology for O&M costs with some of the O&M costs fixed for the term of the New MYR Plan based on a forecast at the beginning of the New MYR Plan, some components updated annually using a formula based on an established inflation factor, and some components re-forecasted and updated annually (like costs subject to annual bidding and items outside of Green Mountain's control). Finally, the New MYR Plan starts with base rates established in a traditional rate case for fiscal year 2023, described below, and contains an option to further smooth rates between fiscal years 2024-2026 if warranted and approved by the VPUC. Like the MYR Plan, the traditional rate case (filed on January 1, 2022 and in effect since October 1, 2022) will serve as the base year for adjustments for each fiscal year of the New MYR Plan.

In August 2022, the VPUC approved Green Mountain's application with no substantive changes to Green Mountain's proposal and its parameters took effect on October 1, 2022. The New MYR Plan is designed to respond to the changing energy landscape and to support Green Mountain's efforts to continue introducing transformative energy programs to the benefit of customers while also providing a reliable, safe, inexpensive and low carbon-emission form of energy through a more resilient and modern network. The New MYR Plan incorporates Green Mountain's Climate Plan work to permit further investments in grid hardening, undergrounding, and operations technology to improve reliability and resilience. The New MYR Plan also supports Green Mountain's current and ongoing technology investments and permits Green Mountain to seek approval for additional cybersecurity investments.

iii. 2023 Fiscal Year Base Rate Case

In January 2022, Green Mountain filed its fiscal 2023 rate case application with the VPUC. Prepared using the parameters of the New MYR Plan simultaneously reviewed by the VPUC, the rate case sought to maintain the 8.57% return on common equity and presents a common equity ratio of 50%, a 2.34% increase in base rates, and a rate base of US$1,768 million, up US$104 million from the 2022 rate case. In August 2022, the VPUC approved Green Mountain's application with minor adjustments agreed to during the approval process. The final decision provided for a 2.18% increase in base rates, which took effect on October 1, 2022.

iv. Integrated Resource Plan 2022 Fiscal Year

In December 2021, Green Mountain filed an Integrated Resource Plan («**IRP**») as required by the VPUC every three years. The IRP is a comprehensive review of customer programs, system investments, innovative programs, power supply portfolio choices, and service quality results that is designed to provide the VPUC an opportunity to review and approve Green Mountain's planning framework for the upcoming years. Green Mountain's IRP incorporated its Climate Plan, as set forth in the VPUC's approval of the Climate Plan, so that investments both for reliability and resiliency would be incorporated into the IRP. Green Mountain and the Vermont Department of Public Service agreed that the IRP is complete and comprehensive, and submitted in September 2022 a joint Memorandum of Understanding and Proposal for Decision, which the VPUC approved on November 22, 2022.

v. Climate Plan

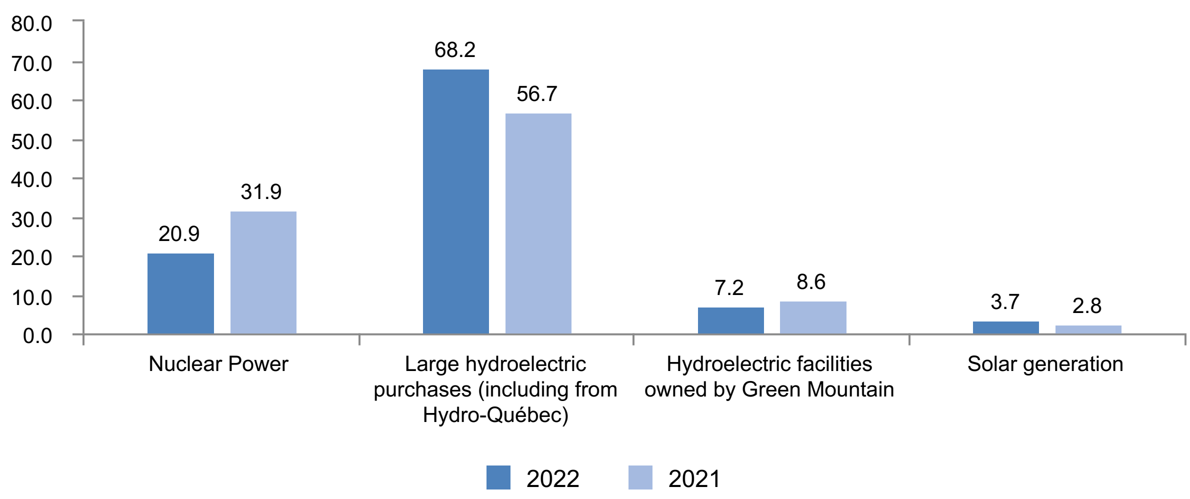
Green Mountain's authorization to file a Climate Plan allowed it to propose resiliency expenditures in addition to base capital plan and targeted operational and maintenance expenses that already are robust in order to address the impacts of climate change.

The Climate Plan approved by the VPUC on September 24, 2020, had two interrelated goals, which were to (1) harden Green Mountain's grid and restoration response in the face of increasing frequency of storms driven by the climate crisis to better serve customers; and (2) better prepare the grid to serve as the backbone for Vermont's aggressive goals to cut greenhouse gas emissions and transition off fossil fuels. These goals helped customers by targeting the interrelated needs of reliability and resiliency. The Climate Plan allowed Green Mountain to invest up to US$14 million per year for fiscal years 2020, 2021 and 2022, in addition to capital investments allowed under the MYR, in projects that Green Mountain would not have pursued but for the need to respond to more frequent and damaging storms, changing weather patterns and changing environmental conditions driven by climate change. Climate planning and resiliency work now is incorporated into the New MYR Plan and the IRP. Green Mountain's 2023 fiscal year base rate filing for rates effective October 1, 2022 and the new MYR Plan that will be in effect through fiscal year 2026 now incorporate climate plan projects in the approved capital investment amounts.

b) Supply Sources

Green Mountain's territory covers approximately two-thirds of the State of Vermont's geographic area. Although it produces part of the electricity it distributes, Green Mountain meets most of its customer demand through a series of short- and long-term contracts. Its supply portfolio includes various generation sources, the main ones being hydroelectricity and regional system energy purchases.[21] The following graph illustrates the breakdown of Green Mountain's power sources for fiscal years 2022 and 2021:

Distribution of Sources Portfolio (1)



(1) The data in this graph reflect the treatment of supply sources from which RECs (as defined and explained under Item 4.1.2.1 e) iv. *Renewable Energy Programs and GHG*) and other carbon free-generation attributes were retained or retired. Accordingly, the amount of energy attributable to the various sources could be significantly lower or higher without consideration of the RECs or other attributes. Data for fiscal year 2021 are subject to further review under the RES (as defined and explained under Item 4.1.2.1 e) iv. *Renewable Energy Programs and GHG* for renewability and carbon contribution from generation supply sources. This review is based upon calendar year 2022 reporting and will be completed in August 2023.

Green Mountain met essentially all of its load requirements in fiscal year 2022 through its contracts and owned generation and other power supply resources. Green Mountain's contracts and resources significantly reduce Green Mountain's exposure to volatility in wholesale energy market prices. The prices in these contracts, along with those of other resources in Green Mountain's diverse portfolio of supply sources, allow Green Mountain to enjoy stable and competitive retail electric rates compared to other utilities in the State of Vermont and elsewhere in New England. To address the impact of climate change, in April 2019, Green Mountain announced its goal to have a 100% carbon free energy portfolio by 2025 and 100% renewable energy by 2030 through direct sourcing, retirement of RECs or a combination of both. In calendar years 2020 and 2021, Green Mountain accomplished this carbon free goal earlier than

[21] Regional system energy purchases include primarily short-term contracts with various counterparties in the normal course of business, as well as purchases in the real-time power market to balance long- and short-term open power positions.

targeted with contracts and attribute retirements that enabled a carbon-free supply portfolio. These goals exceed Vermont's requirements.

Additional information regarding Green Mountain's supply sources can be found in section B) *Conditions in the Energy Market and for Énergir, L.P.* on page 13 of the 2022 MD&A.

i. Hydro-Québec Contract

In August 2010, Green Mountain and 17 other State of Vermont utilities, entered into a long-term Power Purchase and Sale Agreement with Hydro-Québec Energy Services (U.S.) Inc. ("**HQUS**"), a subsidiary of Hydro-Québec, for the purchase of a portion of 225 MW of energy and a portion of the environmental attributes (such as, for example, credits, benefits or emission reductions) ending in 2038. HQUS markets electricity from Hydro-Québec's generating fleet, whose output is over 99.0% hydroelectric. This purchase contract is Green Mountain's most significant power supply contract. The HQUS contract provides Green Mountain with continued access to a reliable and low carbon supply of power from Hydro-Québec facilities.

ii. NextEra Energy Seabrook

The power purchase agreement entered into with NextEra Energy Seabrook, LLC for long-term energy and capacity from the Seabrook Nuclear Power Plant in New Hampshire, which expires in 2034, is a fixed-price contract in which the price is adjusted according to an inflation mechanism designed to protect customers from the inevitable fluctuations in energy prices. In fiscal year 2022, Green Mountain used 55 MW of power from the Seabrook plant and will gradually reduce the quantity to 50 MW before the end of the contract.

iii. Great River

In 2021, Green Mountain received a *Certificate of Public Good* from the VPUC to purchase hydroelectric output and RECs from Great River Hydro, LLC's ("GRH") facilities on the Connecticut and Deerfield Rivers. Through a power purchase agreement entered into on March 2, 2021, with GRH, Green Mountain will begin taking deliveries of energy and RECs in January 2023. There are three distinct products covered by said power purchase agreement including baseload energy, peaking product, which is hydroelectric output that is shaped to meet high demand periods in New England that tend to have higher than average market prices, and level annual REC purchases of 800,000 MWh including the RECs associated with the energy purchased. The two energy products are structured so that the energy volumes delivered grow between 2023 and 2033 and then remain at a constant through the end of the long-term contract on December 31, 2052. The baseload product begins to deliver 5MW around the clock in 2028 and grows by 5MW per year until it reaches its maximum volume of 30MW in 2033. The peaking product begins deliveries in 2023 with Green Mountain purchasing 5% of the anticipated 600,000 MWh output of the shaped hydroelectric output from GRH's Fifteen Miles Falls facilities. This percentage will increase annually until Green Mountain is purchasing 50% of the facilities' output in 2029. The REC purchase is designed to ensure that Green Mountain has a stable, long-term supply of Vermont Tier I eligible RECs that can be retired to meet Green Mountain's obligations under the Vermont RES (as defined and explained in Item 4.1.2.1 e) iv. *Renewable Energy Programs and GHG*) and Green Mountain's long-term renewable goals.

On October 12, 2022, after the close of Green Mountain's fiscal year, Hydro-Quebec announced a purchase agreement to acquire all assets and liabilities of GRH, subject to regulatory approvals. The power purchase agreement entered into on March 2, 2021, requires Green Mountain's consent for this acquisition; which will be evaluated in the course of the regulatory proceedings. Should the transaction be approved by regulatory agencies, the power purchase agreement entered into on March 2, 2021, will remain in effect on the same terms and conditions.

iv. Other material contracts

Green Mountain has two long-term contracts to purchase renewable energy from Granite Reliable Power, LLC at stable, long-term prices until 2032. Green Mountain also has a long-term contract to purchase renewable energy from Deerfield Wind Power, LLC's southern Vermont facility, at stable, long-term prices until 2042.

Green Mountain also makes purchases of energy under short-term contracts with various counterparties in the regional market in the normal course of business. These contracts are typically less than five years in duration.

v. Electric Facilities

Green Mountain owns 42 small hydroelectric generating facilities throughout New England, and the output of these facilities is included in Green Mountain's supply portfolio.

vi. Kingdom Community Wind Generation Facility

The output generated by the 63 MW Kingdom Community Wind generation facility owned by Green Mountain and located in the Town of Lowell, State of Vermont is included in Green Mountain's supply portfolio.

c) Customers and Competitive Position

The following chart illustrates the breakdown of Green Mountain's customers by deliveries in terms of gigawatt hours ("**GWh**") and revenues during the fiscal years 2022 and 2021:

Electricity Deliveries and Revenues Generated								
	Deliveries (in GWh)		% of GWh Delivered by Customer Class		Revenues (millions $ US)		% of Revenues by Customer Class	
	2022	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**
Residential Customers	1,568.3	1,572.7	37.9	38.4	317.7	304.1	45.4	45.9
Small & Medium Consumption Commercial & Industrial Customers	1,451.3	1,409.2	35.0	34.4	252.5	234.6	36.1	35.4
High Consumption Commercial & Industrial Customers	1,116.1	1,111.4	27.0	27.1	126.6	121.5	18.1	18.3
Other Customers	3.7	3.8	0.1	0.1	2.7	2.6	0.4	0.4
Total	**4,139.4**	**4,097.1**	**100.0**	**100.0**	**699.5**	**662.8**	**100.0**	**100.0**

The quantity of electricity delivered by Green Mountain can vary significantly in response to seasonal changes in weather or unusual or severe temperatures. Unlike Énergir, L.P., for the purposes of regulatory accounting, Green Mountain does not have a temperature and wind normalization mechanism, and its deliveries therefore vary based on actual temperature and wind velocity. Green Mountain's New MYR Plan, including the revenue decoupling mechanism described under Item 4.1.2.1 a) i. *Multi-Year Regulation Plan, Fiscal Years 2019- 2022* that remains in effect under the New MYR Plan, mitigates some of the effects of deviations in the sale of electricity resulting from weather and temperatures that are outside a utility's control.

Green Mountain's largest customer, GlobalFoundries Inc. ("**GF**"), accounted for 9.2% of gigawatt hour deliveries, and 5.0% of retail revenues for fiscal year 2022. The next largest customer accounted for 3.9% of gigawatt hour deliveries, and 2.4% of retail revenues for fiscal year 2022. In December 2018, the VPUC approved a multi-year term contract between Green Mountain and GF, Green Mountain's only Rate 70 Transmission Class customer (meaning it takes service directly from a high-voltage transmission grid and has peak demands in excess of 10 MW), to provide the customer with stable and predictable energy costs through a fixed rate. In exchange, GF agreed to maintain its power use on site, and forgo credits or rate cuts flowing to other Green Mountain customers during the term of the contract, including the federal income tax savings returned to other customers during the nine-month rate period. The term contract is effective from January 1, 2019 up through September 30, 2023 if needed, as described immediately below.

In March 2021, GF filed a petition with the VPUC to operate a self-managed utility effective in fiscal year 2023 at the end of Green Mountain's MYR Plan. Scheduling changes delayed the VPUC proceeding to review the petition past the end of the MYR Plan in fiscal year 2022; to accommodate that scheduling delay the term contract between Green Mountain and GF was extended for up to a year through the end of fiscal year 2023 or the closing of the transaction contemplated in the GF petition, whichever is first.

The VPUC approved the GF petition on October 21, 2022. GF is now authorized to complete all steps necessary to take over electric service for its Vermont business and to manage its own electric supply after a transition period that will last through fiscal year 2026, to align with Green Mountain's New MYR Plan period. The VPUC simultaneously approved Green Mountain's petition to modify its service territory to remove GF's Essex, Vermont campus from Green Mountain's service territory once GF begins serving its own electricity needs. In order to reduce the impact of a GF transition on Green Mountain's other customers, Green Mountain and GF entered into a Letter of Intent pursuant to which GF will enter into a Transitional Power Purchase Agreement through fiscal year 2026 ("**Transitional PPA**"). Under the Transitional PPA, Green Mountain will provide GF its full energy and capacity requirements during Green Mountain's fiscal years ending September 30, 2023 to September 30, 2026 (the "**Transition Period**"), and GF will pay a transition fee of US$15.6 million. The Transitional PPA will be GF's contribution to Green Mountain's revenue requirement during the Transition Period.

In Green Mountain's market, competition can take several forms. At the wholesale level, in New England, a detailed competitive market framework was implemented that has resulted in bid-based wholesale competition of power suppliers rather than prices set under cost of service regulation. At the retail level, in addition to electricity, customers have energy options such as propane, natural gas or oil for heating and water heating. There also exists the potential for municipalities located in Green Mountain's service territory, with the citizens' approval, to form and operate municipally owned utilities.

In addition, self-generation, demand side management programs and cogeneration can lower network electric sales by displacing supplied electric demand within Green Mountain's service territory and potentially reducing the customer base over which Green Mountain costs are spread, driving up costs for remaining customers. As of September 30, 2022, approximately 692MW of self-generation was installed on behalf of Green Mountain's customers, compared to approximately 240 MW in fiscal year 2021. This represented approximately 8.0% of Green Mountain's total deliveries in fiscal year 2022, compared to approximately 7.0%[22] in fiscal year 2021. While advanced self-generation technologies can lower Green Mountain's sales thereby increasing rates for customers, this trend may be partially offset by innovative energy transformation initiatives through RES (as defined and explained under Item 4.1.2.1 e) iv. *Renewable Energy Programs and GHG*), including the setting of goals for energy transformation projects. Green Mountain has undertaken a series of initiatives to offset decreased sales for customers and satisfy RES' goals through investing in storage, efficient electrification, and integrated energy services. Green Mountain's New MYR Plan also mitigates some of the effects on its net income of deviations in the sale of electricity resulting from self-generation, demand side management programs, and cogeneration. Additionally, in April 2019, the VPUC commenced a proceeding to review the net metering rule including its rate structure. Green Mountain is participating in this proceeding. The VPUC has not yet issued an order in this proceeding.

Additional information regarding Green Mountain's strategic partnerships and innovative products and services can be found in section D) *Segment Results* on pages 23 and 24 of the 2022 MD&A.

d) System Operations

Green Mountain's primary goal with its system operations is to provide reliable, safe, cost-effective and increasingly distributed renewable and carbon free energy solutions for its customers. For fiscal year 2022, Green Mountain delivered its capital asset management plan in the amount of US$59.9 million with projects targeted to improve reliability and resiliency of its system including tree trimming, fuse coordination, sectionalizing, new infrastructure and reconstruction in three areas: transmission, distribution and substations.

Green Mountain also has an integrated, long-term vegetation management program, pole inspection system and participates in and adheres to the procedures thereof. Dig Safe® notifies participating utilities of plans to excavate in areas where underground facilities may be present. Green Mountain also has formalized its practices for inspecting overhead and underground distribution equipment and conducts aerial patrol of its entire subtransmission system every spring and fall, and after major storms, to locate, assess and fix any damage.

Given the climate changes that are causing an increase in the frequency and severity of storms, Green Mountain has taken steps to make the grid safer and more resilient. To address these climate changes and their impact, over the past ten years, Green Mountain has been consistently investing capital in important resiliency projects to harden the system and modernize the grid. Examples include hardening the system against disruption events by moving cross country sections to roadside and enhancing storm restoration and forecasting capabilities. Green Mountain also has encouraged and invested in local, distributed generation and distributed energy sources such as battery backup systems. Incorporating the Climate Plan goals and objectives into Green Mountain's New MYR Plan, as discussed above, furthers Green Mountain's ability to make these important investments.

e) Environmental Protection

i. <u>Environmental Policy</u>

Green Mountain is committed to environmental action, awareness and accountability in all its business practices and operations. Green Mountain is further committed to ensuring safe and healthy working conditions in all its facilities for employees. Green Mountain has in effect certain procedures, plans, and guidelines applicable to environmental matters adopted in the normal course of business. Additionally, Green Mountain has a Code of Ethics and Conduct, approved by the Green Mountain Board, applicable to all directors, officers, employees and agents of Green Mountain.

Green Mountain's by-laws include a requirement that the board of directors consider the environment and how to use energy as a force for the common good in the board of directors' decision-making process. This is one of the requirements for Green Mountain to be eligible for certification as a "Certified B Corporation" pursuant to the

[22] The 2021 Annual Information Form indicated that the installed megawatts of self-generation represented approximately 9.3% of Green Mountain's total deliveries in fiscal year 2021. The percentage that should have been indicated is 7%.

requirements and performance standards of B Lab, a non-profit organization, which certifies companies who voluntarily meet higher standards of social and environmental performance, transparency and accountability. Green Mountain submitted its recertification application in January 2020. The recertification process occurs every three years, and Green Mountain was recertified in November 2021 after being delayed due to COVID-19.

Green Mountain actively seeks out opportunities to minimize the impacts of all wastes resulting from its activities through reduction, reuse and recycling. For example, Green Mountain ships retired electrical equipment to facilities capable of decontaminating and recycling nearly all of the component parts and ships waste mineral oil dielectric fluid to a facility that decontaminates and re-refines it for use in new electric equipment. Through these efforts, in calendar year 2021, Green Mountain recycled approximately 15,500 U.S. gallons of oil in addition to the oil contained in retired transformers and other equipment shipped intact for recycling and disposal.

ii. Environmental Laws, Rules and Regulations

Green Mountain's operations and facilities are subject to U.S., state and local laws, regulations and permits regarding the environment.

Green Mountain is also required to obtain and comply with many different permits and certificates, issued by federal, state and local authorities that govern its operations and facilities. Many of these permits contain terms and conditions that are designed to protect the environment.

iii. Environmental Matters

Green Mountain has been cited as being potentially liable for polluting land on which a manufactured gas plant that ceased operations in 1966 was located. In 1999, a settlement protocol was signed between the U.S. Environmental Protection Agency ("**EPA**") and the enterprises involved (including Green Mountain). It included an action plan to restore the site and a cost-sharing method. This action plan was approved by the VPUC in 2001 and has generally proven effective, except for a portion of the contaminated area, for which the EPA mandated the installation of an additional remedial device.

For fiscal year 2022, Green Mountain incurred approximately US$333,587 related to such site, compared to approximately US$308,583 in fiscal year 2021. The fiscal year spending includes ongoing monitoring which continues to confirm that the site remedy is adequate. The EPA issues a review of the project every five years ("**Five Year Review**"). In late December 2021, the EPA issued its fourth Five Year Review for the project and concluded the site remedy continued to function as intended, and the review did not identify any information questioning the effectiveness of the remedy. In fiscal year 2022, there has been considerable interest in business development on adjacent property. Green Mountain is cooperating with developers to assure any adjacent development will not affect the site remedy. Non-Government Organizations have also conducted trash clean-up events at the site. The EPA's Five Year Review encourages Green Mountain, Government Organizations and Non-Government Organizations to ensure future recreational use of the site is protective of human health and is consistent with the site remedy. The VPUC has agreed that the costs incurred to date by Green Mountain can be recovered in rates over a period of 10 to 20 years. If future outlays exceed the provisions already recorded on the books, new requests to recover such amounts in rates will be submitted to the VPUC.

iv. Renewable Energy Programs and GHG

- *Renewable Energy Standard and Renewable Energy Certificates*

Green Mountain is subject to the State of Vermont's policy encouraging the development of renewable energy sources in the State of Vermont as well as the purchase of renewable power by the State's electricity distributors. The Vermont Department of Public Service's "Comprehensive Energy Plan" sets a goal to have 90.0% of the State of Vermont's energy needs come from renewable sources by the year 2050. In 2020, the State of Vermont passed the Global Warming Solutions Act, described below, requiring certain GHG reductions across all energy use sectors by 2025, 2030 and 2050.

Additionally, the Vermont renewable energy law establishing a mandatory Renewable Energy Standard ("**RES**") for Vermont utilities specifically requires that retail electricity providers: (1) have a minimum amount of renewable electricity in their supply portfolios; (2) support relatively small (less than 5 MW) new renewable energy projects connected to the Vermont grid; and (3) invest in projects to reduce fossil fuel use for heating and transportation. The renewable energy sources requirements under this new law began in 2017 and escalate in quantity until 2032. Green Mountain met or exceeded all three tiers of its calendar year 2021 RES obligations, is well-positioned to comply with the RES and expects to meet the calendar year 2022 goals.

Green Mountain has an increasing number of renewable energy sources in its long-term supply portfolio as a result of Vermont's former Sustainably Priced Energy Enterprise Development Program (commonly referred to as "**SPEED**") and of Green Mountain's own commitment to the development of renewable energy resources. Under RES, only energy sources that are represented by Renewable Energy Certificates ("**RECs**") which are retained and retired by the utility for the purpose of meeting RES requirements may be counted toward each utility's requirements. Renewable energy sources produce RECs, and a REC represents evidence that one megawatt hour of electricity was actually generated and delivered within the New England region from an eligible source.[23] While Green Mountain can purchase and sell RECs, in order to qualify as renewable energy sources under RES, a sufficient number of RECs that correspond to Green Mountain's resource requirements must be retained and retired. As required by statute, the VPUC commenced a rulemaking proceeding for the RES in which it addressed, among other issues, the types of RECs or environmental attributes that may satisfy the RES. Specifically, the VPUC determined that Hydro-Québec environmental attributes are eligible for RES compliance regardless of whether they are purchased with energy. Energy purchased under the contract with HQUS described above under Item 4.1.2.1 b) *Supply Sources* includes environmental attributes, but Green Mountain also purchases environmental attributes under separate contracts with HQUS, tied to transmission rights rather than energy. The latter contracts remain in effect for the next several years, so the VPUC determination that Hydro-Québec environmental attributes need not be purchased with energy in order to comply with the RES is favourable for customers.

Many states in Green Mountain's surrounding geographic region have adopted renewable portfolio standards that require electricity distributors in those states to produce a certain amount of energy from renewable sources. Green Mountain is not subject to renewable portfolio standards in other states. Green Mountain currently sells RECs from its sources to these surrounding states to help reduce net power costs for the benefit of customers. The sale of RECs totalled approximately US$17.3 million in fiscal year 2022, compared to approximately US$12.3 million in fiscal year 2021. The value and volume of RECs available to sell depends on many factors.[24] For fiscal year 2022, the price was comparable to fiscal year 2021, but premium REC volumes were higher overall. Due to market demand, Green Mountain also sold RECs from small existing hydroelectric resources, for an additional US$1.5 million in revenue that lowered power supply costs for customers.

Green Mountain's future revenue from the sale of RECs is uncertain due to the intermittent nature of production from the renewable energy sources and variation in the market prices for RECs. In addition, Green Mountain's ability to sell RECs, and the level, type and price of such RECs, in the future is made uncertain by potential changes in renewable energy and carbon policy in the State of Vermont or in surrounding states, along with Green Mountain's own long-term carbon and renewable goals.

The third tier of the RES establishes annual compliance goals tied to Green Mountain's support for projects and measures that reduce fossil fuel consumption by Green Mountain customers in order to address climate change. The goals are set and measured in megawatt hours that are roughly equivalent to RECs. Green Mountain meets these goals (1) with residential programs, focused on replacing fossil fuel heating with cold climate heat pumps, and replacing fossil fuel-based transportation with electric vehicles; and (2) by supporting projects for commercial and industrial customers that remove or reduce fossil fuels from heating, diesel generation, compression and other industrial processes. Many of these projects leverage beneficial electrification, which not only reduces fossil fuels, but improves operations and cuts costs for participating businesses and builds load that benefits all Green Mountain customers through lower costs. These efforts, which began in 2017, have supported projects that will offset over 450,000 lifetime tonnes of CO_2. Calendar year 2022 projects are forecast to offset an additional 476,000 lifetime tonnes of CO_2.

- *Global Warming Solutions Act*

On September 22, 2020, the Vermont Legislature passed Act 153, also known as the *Global Warming Solutions Act* ("**GWSA**") which established the Vermont Climate Council and set forth several GHG reduction requirements for the State to meet. The Act requires reductions in Vermont's GHG emissions tied to three time periods: 2025, 2030, and 2050. Pursuant to the State's membership in the United States Climate Alliance and commitment to implement policies to achieve the objectives of the 2016 Paris Agreement, Vermont is required to reduce its GHG emissions by no less than 26% below 2005 GHG emission levels by January 1, 2025. The first Climate Plan under the GWSA was released in December 2021. Legislation tied to its recommendations will continue to be considered in the upcoming legislative session. Investments, such as in electrified transportation and heating and in infrastructure upgrades necessary to support that, were included in the most recently-passed Vermont state budget and future investments in line with the GWSA will continue to be proposed through the Vermont budget process and through use of federal appropriations to Vermont. State rulemaking for vehicle emissions tied to the Climate Plan is presently underway; Vermont continues to follow California emissions standards for vehicles and is in the midst of adopting California's most recent update, through what is known as Advanced Clean Cars II rulemaking, to phase out most internal combustion light duty,

[23] RECs can be sold and traded independent of the underlying energy, and the owner of the REC can claim to have purchased renewable energy.
[24] These factors include the year the RECs were issued, the type and location of the renewable energy source, and the relationship of supply and demand.

passenger, truck and SUV sales from manufacturers by 2035. Further rulemaking and legislation to implement the GWSA's mandated reductions are expected to occur in the upcoming years.

- *Solar Energy and Battery Storage*

Furthering the goals of state energy policy and Green Mountain's commitment to solar development and energy storage, Green Mountain has constructed and commissioned five projects that pair utility-scale solar with battery storage and four utility-scale solar projects, all of which are used to advance Green Mountain's strategy to target peak loads to reduce power supply and transmission costs to drive down costs for customers. Green Mountain also was the first utility to launch a Tesla Powerwall pilot program, and through a series of groundbreaking programs, Green Mountain was the first utility with tariffed home energy storage programs for customers. These programs provide participating customers with clean, seamless backup power in residential batteries in exchange for sharing some of that stored energy to reduce peak demand on the grid. There are about 4,100 Powerwalls installed in customers' homes along with batteries from other manufacturers, and Green Mountain's network of stored energy, including Powerwalls, car chargers, and utility-scale batteries, helped reduce costs for customers by more than $3 million in calendar year 2021 through peak reduction.

- *Renewable Net Metering Program*

As part of a state program, Green Mountain also offers customers a renewable energy rate permitting customers to receive monetary credits against their retail bills for renewable generation produced by the customer's net metering system. The credits can vary depending on the date that the net metering system was commissioned.

f) Energy Efficiency

Efficiency services to customers are primarily provided through an energy efficiency utility, which is financed through a separate charge on electric bills. As part of the third tier of the RES, Green Mountain works with its customers and the efficiency utility to find opportunities to replace fossil fuel use with efficient smart electrification in areas such as building heat and transportation. Additionally, Green Mountain may provide incentives for efficiently electrifying business processes that were previously dependent on fossil fuel such as installation of line extensions to replace diesel generators.

g) Climate change

i. Climate Change Risks and Opportunities

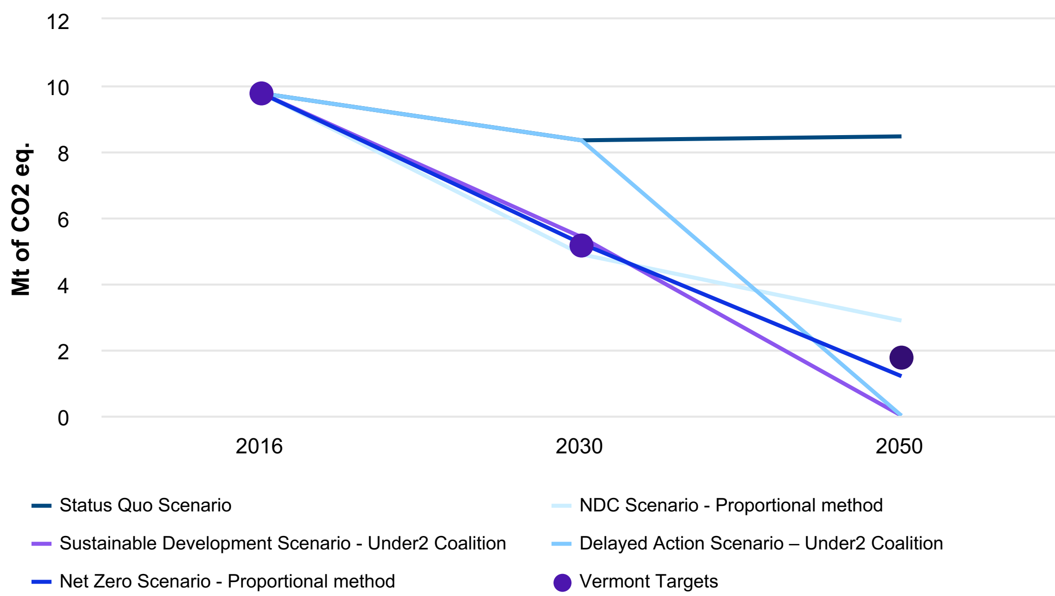
Green Mountain may be exposed to climate change risks and opportunities. In this context, Green Mountain assessed such risks and opportunities, which are described in Item 4.1.1.6 a) *Climate Change Risks and Opportunities*. In fact, Énergir, L.P., Green Mountain and Vermont Gas all used a common methodology to assess their risks and opportunities.

ii. GHG Emissions Scenarios over the 2030-2050 Horizons

In order to interpret the meaning of the global scenarios presented under Item 4.1.1.6 b) i. *Global Scenarios* above for Green Mountain, they have been scaled to the jurisdiction of Vermont. Green Mountain and Vermont Gas[25] used the Under2 Coalition methodology where applicable and, in other cases, the proportional methodology, as more fully described in the *Quebec-Wide Scenarios* section. The Under2 Coalition methodology is relevant to Vermont, which is a member of the Under2 Coalition. The proportional methodology is also relevant for Vermont when the Under2 Coalition methodology cannot be applied. Indeed, the proportional methodology consists in transposing the percentage of emission reductions at the global level to Vermont.

As seen in the Quebec-wide scenarios, the scaling of the NDC Scenario for Vermont reveals a net drop of GHG emissions in 2050. These emissions should reach nearly 3 million tonnes of CO_2 eq. in 2050, though they were estimated at close to 4 million tonnes in 2021. Once again, the pathway by 2030 remains unchanged.

Possible annual GHG emissions pathways according to the scenarios used as they apply to Vermont (expressed in million tonnes of CO2 eq.)



(25) The scaling for Vermont applies to Énergir, L.P.'s two subsidiaries, Green Mountain and Vermont Gas, which are in Vermont. This is why Vermont Gas is included in this item.

The above-mentioned scenarios may have the following impacts:

<table>
<tr><th>SCENARIOS</th><th colspan="2">DESCRIPTION OF IMPACTS</th></tr>
<tr><th></th><th>GREEN MOUNTAIN</th><th>VERMONT GAS</th></tr>
<tr><td>Status Quo</td><td colspan="2">Distributed volume would remain relatively stable beyond 2030. Global temperatures could rise by 3.6°C; in such a case, climate change would be likely to affect certain physical assets such as hydroelectric assets (increase in water level and volume, especially during very intense rainfall events), transmission and distribution (accelerated vegetation growth rates, stress on trees resulting from rising temperatures, isolated flooding episodes) of Green Mountain or Vermont Gas assets.</td></tr>
<tr><td rowspan="2">NDC</td><td colspan="2">Compliance with Vermont's GHG emission reduction policies and achievement of Vermont's GHG emission reduction targets would result in significant changes to the current traditional business model of Green Mountain and Vermont Gas. Because physical impacts of climate change over the next decade are driven by past GHG emissions, at least some of their above-mentioned physical effects would be felt even if the NDC Scenario materializes. A global warming above 2°C would nevertheless have significant physical repercussions.</td></tr>
<tr><td>Some markets would be affected, such as building heating and transportation, for which less emissive alternatives are available through electrification. These changes would benefit Green Mountain customers by increasing the load and reducing the pressure on rates.</td><td>Some markets would be affected, such as building heating and transportation, for which less emissive alternatives are available through electrification.</td></tr>
<tr><td rowspan="3">Sustainable Development and Delayed Action</td><td colspan="2">The physical impacts of climate change would be the same, but they are expected to affect Green Mountain and Vermont Gas customers at different times and in a less severe way. In both scenarios, global warming is limited to 2°C or less by 2100 and therefore the assets and customers of Green Mountain and Vermont Gas would be less disrupted by climate change after 2040.</td></tr>
<tr><td>In the Sustainable Development Scenario, the energy transition is underway and is faster, but stable by the 2030 and 2050 horizons. Green Mountain would benefit from this.</td><td>In the Sustainable Development Scenario, the energy transition is underway and is faster, but stable by the 2030 and 2050 horizons. Vermont Gas would have to continuously deal with sustained transition risks.</td></tr>
<tr><td>In the Delayed Action Scenario, the actions needed to limit global warming to 2°C do not occur until a sharp change in policies after 2030. In this case, managing Green Mountain's portfolio and operating activities to maintain a clean, cost-effective and reliable energy system would be key to helping its customers.</td><td>In the Delayed Action Scenario, there is a possibility of a shock (a sharp change in policies after 2030 affecting Vermont Gas directly or its customers' activities). In this case, adapting Vermont Gas' business model to control the risks associated with this transition could represent a considerable challenge. These scenarios are consistent with limiting temperature rise to 2ºC or less by 2100 compared to pre-industrial levels.</td></tr>
<tr><td rowspan="2">Net Zero</td><td colspan="2">Despite limiting temperature increases, physical risks are still expected, but are mitigated by prompt and concerted action. The current and announced policies so far do not allow the realization of the Net Zero Scenario.</td></tr>
<tr><td>Green Mountain customers would reap maximum benefits from the Net Zero Scenario through greater load growth, thus reducing pressure on rates. While the decarbonization effort will be major for all sectors of the economy by 2030 to limit the temperature to 1.5ºC compared to the pre-industrial era, this scenario imposes increased transition risks, but creates very favourable conditions for the implementation of its decarbonization solutions.</td><td>In the Net Zero Scenario, Vermont Gas has to continually deal with sustained transition risks in the short term. While the decarbonization effort will be major for all sectors of the economy by 2030 to limit the temperature to 1.5ºC compared to the pre-industrial era, this scenario imposes increased transition risks for the gas distributor, but creates favourable conditions for the implementation of its decarbonization solutions.</td></tr>
</table>

iii. Sustainability of Green Mountain's Business Model

To address climate risks and opportunities, Green Mountain's *Path to 100% Renewable* has one priority: customers – how best to serve them cost effectively and reliably in this time of climate change, and to offer them the latest available technologies. Green Mountain is providing clean, cost-effective, and reliable power, as more and more customers choose strategic electrification. For these purposes, Green Mountain has adopted a proactive and detailed Climate Plan, with ambitious goals that exceed Vermont's regulatory requirements, to achieve 100% carbon-free electricity supply on an annual basis by 2025 and 100% renewable by 2030. In fact, Green Mountain has exceeded the goal of getting to 100% carbon free by four years (through direct sourcing, the retirement of carbon-free generation attributes or a combination of both), as explained in Item 4.1.2.1 b) *Supply Sources*. As of September 30, 2022, Green Mountain's annual electricity supply portfolio is 100% carbon free and 78% renewable.

Because Green Mountain's supply portfolio is already decarbonized, it is less exposed to the transition risks inherent to climate change. This is why Green Mountain is focusing on physical resilience risks to develop an energy system where generation is closer to end users, interconnected and empowering for customers, which requires:

- switching from a one-way energy system of centralized, fossil fuel-based generation transmitted through traditional electric poles and cables to a power generation system that is lower in GHG emissions, renewable and distributed with new possibilities for managing complex local and regional networks;

- switching from one-way electricity flowing from a central plant, to storage and delivery of a two-way flow between customers and Green Mountain. Green Mountain is deploying a large battery fleet across the network to reduce costs and carbon emissions and increase resiliency for customers;
- leveraging growing demand associated with strategic electrification to decarbonize the transportation and thermal power sectors, major sources of carbon pollution in Vermont; and
- continually improving the resiliency of the energy distribution system and customers' buildings through innovative programs and solutions, including battery storage and smart electric infrastructure in homes and businesses.

Green Mountain is investing in energy distribution models that seek transformation to adapt to the evolving energy generation context in the following ways:

- leveraging many different resources (distributed energy resources) to manage the new, multi-directional grid with intermittent resources. Using battery storage to meet the need previously fulfilled by fossil-fuel generators and retiring these assets.
- establishing communities of distributed energy resources that are communications enabled to optimize the operating cost of the electrical system and the use of renewable and non-GHG-emitting generating sources.
- offering a diverse portfolio of innovative energy programs that promote measures consistent with Vermont's energy policy and appeal to the specific goals of each customer.

Green Mountain invests in resiliency and reliability measures to counter the effects of climate change on its system through its Climate Plan by:

- integrating evolving technology to underground parts of the distribution system to lead to a cost-competitive solution allowing for more burial of lines in locations with reliability issues, notably to reduce exposure of Green Mountain's assets to physical risks of climate change such as severe storms.
- better preparing Green Mountain's grid to serve as the backbone for Vermont's aggressive goals to cut GHG emissions and transition off fossil fuels.
- favouring the creation of resiliency zones to take a targeted approach to communities that have multiple resiliency challenges, including electric, communications and social vulnerability. This helps customers achieve ubiquitous broadband connectivity that is required to unlock innovative energy services that help cut costs and reduce GHG emissions through load management and control. Green Mountain successfully launched a broadband internet service deployment program to quickly help more Vermonters get connected at a lower cost. Green Mountain is in the midst of a federally funded major rollout.

The implementation of Green Mountain's roadmap sert out in *Path to 100% Renewable* is consistent with the GHG emission reduction pathway described in the Sustainable Development Scenario or the Delayed Action Scenario described in Item 4.1.2.1 g) ii. *GHG Emissions Scenarios over the 2030-2050 Horizons*. Green Mountain has set specific targets for itself that are either more stringent than those of the Under2 Coalition of which Vermont is a member, or in line with Vermont's stated objectives.

Green Mountain uses a scenario to assess its climate resilience in a pathway to limit the temperature rise to 1.5°C or less. It is important to clarify that, for the moment, neither Vermont nor the United States have adopted climate targets to align with this pathway. Green Mountain is aware that there are additional emission reductions that would have to be achieved, particularly in the next ten years, if Vermont were to adopt a more aggressive GHG emission reduction pathway than those limiting global warming to 2°C or less. This may have a positive impact on Green Mountain's customers, as the company is already well positioned to offer decarbonized solutions to Vermonters that will grow load, which will reduce the pressure on rates.

iv. Management of Climate Risks and Opportunities

This information can be found in Item 4.1.1.6 d) *Climate Change Risk Identification and Management Practices*.

v. Governance as related to Climate Change Risks and Opportunities

Green Mountain is governed by the Green Mountain Board, which has the power to oversee the management of the business in support of the resilience of Green Mountain for its customers in the short, medium and long term. Green Mountain is managed by its President and Chief Executive Officer. Its corporate governance structure is comprised of the Green Mountain Board, two Board committees and its executive team.

The Green Mountain Board reviews Green Mountain’s strategic goals with management, provides general advice and suggests general guidelines to Green Mountain’s management. The Green Mountain Board currently maintains an audit committee and a CGC and carries out many of its responsibilities through these two committees.

- audit committee: assesses the steps management takes to minimize significant risks or exposures to Green Mountain, including climate-change related risk assessment and risk management policies.
- CGC: reviews developments related to corporate governance matters and management’s short- and long-term goals to achieve good outcomes at lower cost to customers and with reduced GHG emissions.

Green Mountain’s long-term incentive program for executive officers is based on the monitoring of performance indicators and incorporate the following strategic environmental indicator, “decarbonization effort – reduction of greenhouse gas (GHG) emissions.” This indicator tracks GHG emission reductions in Vermont.

h) Equity Interest in Transco and VELCO

As at September 30, 2022, Green Mountain owned a 75.70% direct ownership interest in Transco(26) and a 38.80% direct ownership interest in VELCO. Green Mountain currently receives an approximate 10.57% annual return on these investments from Transco and VELCO, which rate of return is approved by the FERC. The amount of this return is applied to Green Mountain’s regulated retail cost of service to benefit its customers.

VELCO is Vermont’s state-wide electricity-transmission-only company which owns and operates all of the major electricity transmission facilities in Vermont. VELCO is jointly owned by Vermont investor-owned utilities, rural electric cooperatives, and municipal electric systems. Transco owns the high-voltage electricity transmission system in Vermont, enabling electricity transmission service to over 17 electricity distributors in Vermont and two in New Hampshire. It also supplies electricity to New England through ISO-NE, which manages power generation and transmission operations in that region. VELCO is the manager of Transco pursuant to a management services agreement conferring on VELCO the power to manage, in its discretion, Transco’s day-to-day operations. VELCO also owns and operates (through its wholly owned subsidiary, Vermont Electric Transmission Company, Inc.) a transmission line used to transmit electricity purchased by the New England electricity distributors from Hydro-Québec. VELCO and Transco are regulated by the FERC when it comes to rate-setting and financing and by other Vermont regulatory agencies for such matters as the construction of electricity transmission-related assets.

i) Nuclear Investments

Green Mountain has a 1.73% ownership interest in Unit #3 of the Millstone Nuclear Power Station, a 1,229 MW nuclear generating facility located in Waterford, Connecticut. Green Mountain has the right to a share of the output of Unit #3 corresponding to its percentage ownership interest.

Dominion Energy Nuclear Connecticut, Inc. is the lead owner of Millstone Unit #3 with approximately 93.47% of the plant ownership. As a partial owner, Green Mountain has the obligation to fund its ownership percentage share of decommissioning of this plant. There is an external trust fund dedicated to funding these costs. The amount of this trust fund is currently sufficiently funded to cover the expected costs of decommissioning under U.S. Nuclear Regulatory Commission standards. If a need for additional decommissioning funding is necessary, Green Mountain will be obligated to resume contributions to the trust fund, based on its ownership share.

Green Mountain also has a small minority ownership interest in three decommissioned nuclear power plants: 2.0% ownership interest in Maine Yankee Atomic Power Company, 2.0% in Connecticut Yankee Atomic Power Company and 3.5% in Yankee Atomic Electric Company. These plants have been permanently shut down for many years and are completely decommissioned except for the Independent Spent Fuel Storage (“**ISFSI**”) at each location. There are continuing costs relating to long-term ISFSI operations and maintenance, the decommissioning of these plants and other remaining cost obligations, which have historically been funded primarily through sponsor contributions to the decommissioning trust funds for each plant. As a result of litigation payments to these plants from the U.S. Department of Energy regarding liability for spent fuel storage costs, Green Mountain does not have any net estimated future contributions to these trust funds as of September 30, 2022. However, due to changing technologies, new requirements of law and other uncertainties, sponsor contributions to the decommissioning trust funds could resume in the future.

Any of Green Mountain’s contribution to these decommissioning trust funds is recoverable in its rates.

(26) VELCO has a 3.70% direct ownership interest in Transco. Green Mountain’s indirect ownership interest in Transco through VELCO, together with its direct ownership interest, totals 77.13%.

4.1.2.2 Vermont Gas

a) Regulatory Process and Rates

Vermont Gas is regulated by the VPUC. The rates for its activities are established using a cost-of-service method, which enables Vermont Gas to establish its revenues so as to recover the costs it expects to incur to serve its customers, excluding certain items not recoverable in rates, and provides an opportunity to earn a reasonable rate of return on rate base.

Vermont Gas' regulatory capital structure consisted of 50% shareholder's equity for fiscal years 2022 and 2021. Its authorized rate of return on common equity was 8.80% and 8.65% for fiscal years 2022 and 2021, respectively.

Vermont Gas' rates, both base rates recovering non-gas costs and natural gas rates recovering supply costs, are approved by the VPUC. Base rates are generally set on an annual basis while the natural gas rates are adjusted quarterly.

Additional information regarding Vermont Gas' regulatory framework can be found in section D) *Segment Results* on pages 22 to 24 of the 2022 MD&A.

b) Supply Sources and Storage

Vermont Gas obtains nearly all of its natural gas supply from Canada, with the exception of one RNG production facility in Vermont that began injecting RNG directly into Vermont Gas' system in fiscal year 2021. During fiscal year 2022, Vermont Gas had 15 base load supply contracts that provided the majority of Vermont Gas' firm natural gas supply. Numerous other suppliers provided spot supply on an as-needed basis. The price of Vermont Gas' base load supply contracts is generally indexed to recognized, liquid market points.

Of the 15 base load supply contracts, Vermont Gas has three long-term contracts for the purchase of RNG[27] in support of its RNG program. The program provides RNG supply for i) company use at Vermont Gas buildings and gate stations, ii) the Vermont Gas voluntary RNG program, and iii) including RNG as part of its base supply portfolio. One contract started deliveries in February 2020 and is a seven-year contract for volumes of at least 20,000 MMBTUs per year, with the possibility of providing up to 72,000 MMBTUs per year. A second contract started deliveries in July 2021 bringing locally sourced RNG into Vermont Gas' system. The contract is for 20 years and a minimum of 41,640 MMBTUs, but could deliver as much as 180,000 Mcf per year. The third is a 15-year contract for RNG that is expected to begin deliveries in 2023. This contract will deliver to Vermont Gas between 70,000 and 120,000 MMBTUs per year of RNG. In addition to the 15 base load supply contracts, Vermont Gas has an RNG supply contract, which is also a base load contract. It is a 14.5-year contract for 300,000 MMBTUs per year. The deliveries under this contract are expected to begin in January 2023 with approximately half of the supply being delivered to Vermont Gas via Dawn, Ontario, and the other half being delivered to the transportation market with those revenues being used to reduce overall RNG costs for Vermont Gas' customers. This contract includes an option for Vermont Gas to increase volumes each year by 100,000 MMBTUs up to a maximum of 1 million MMBTUs.

In addition, Vermont Gas has a storage contract with Tenaska Marketing Canada, a division of TMV Corp.; said contract was renewed in fiscal year 2022 and expires on March 31, 2024. Under the contract, Vermont Gas delivers natural gas to the Enbridge Gas system at Dawn, Ontario, during the injection season (typically April through October) and Tenaska Marketing Canada, redelivers the gas to the same point as needed during the withdrawal season (typically November to April). Additionally, Vermont Gas has a storage contract with Enbridge Gas System for a small amount of supplemental storage enabling additional winter flexibility, said contract was renewed in fiscal year 2022 and expires on March 31, 2024. The contract with Tenaska Marketing Canada provides the flexibility of the Enbridge Gas System storage contract mentioned above, including off-season injections and withdrawals.

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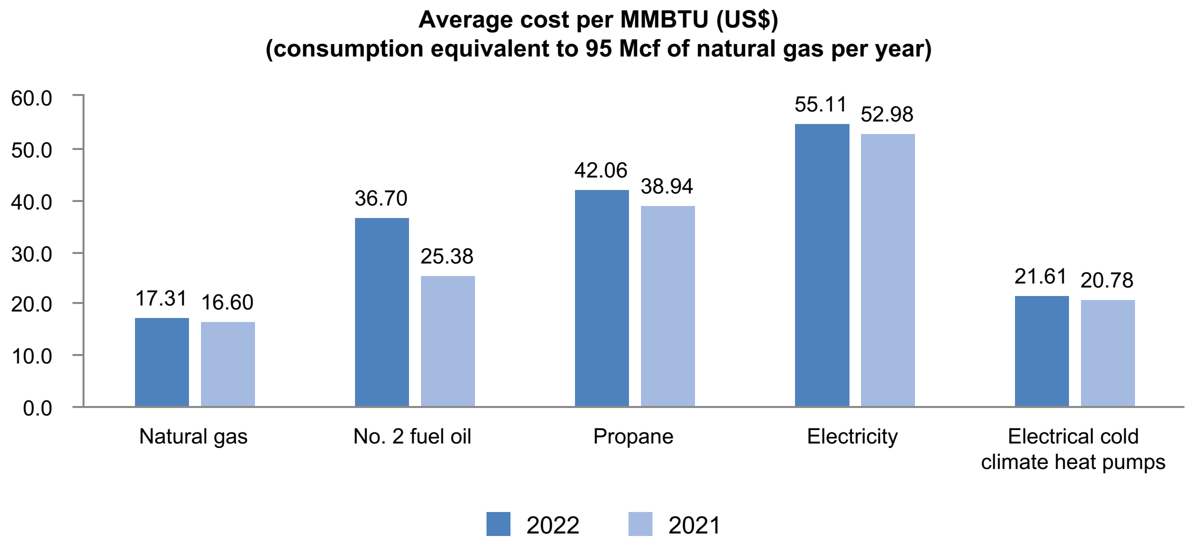
[27] In fiscal year 2022, the three long-term contracts to purchase RNG represented approximately 2% of Vermont Gas' overall supply of natural gas.

c) New Customers

In fiscal year 2022, Vermont Gas delivered 13.7 Bcf of natural gas to its customers, compared to 13.5 Bcf in fiscal year 2021. Based on Vermont Gas and Green Mountain VPUC-approved residential rates and Vermont-specific data from the Vermont Department of Public Service for No. 2 fuel oil and propane, the average cost per MMBTU at the close of fiscal years 2022 and 2021 was as follows:



d) Energy Efficiency

Since the early 1990s, Vermont Gas has offered a comprehensive portfolio of energy efficiency programs to its 55,000+ customers. In fiscal year 2022, Vermont Gas invested US$4.19 million in its energy efficiency programs, slightly lower than the amount invested in fiscal year 2021, which totaled a little more than US$4.2 million. In fiscal year 2022, annual savings were in excess of 0.05 Bcf, compared to annual savings of approximately 0.065 Bcf in fiscal year 2021. This made it possible to avoid 3,261 tonnes of GHG emissions in 2022, and 4,003 tonnes in 2021. This helped to prevent the emission of 3,261 tonnes of GHG in 2022 and 4,003 tonnes of GHG in 2021. COVID-19 recovery, inflation and the war in Ukraine continue to drive a series of economic disruptions. The decrease from fiscal year 2021 to fiscal 2022 in spending by Vermont Gas on its energy programs and in annual savings, can be explained by the impact of higher material costs, limited material availability and contractor workforce constraints that contributed to longer lead times and unexpected delays moving commercial and new construction projects to completion. Vermont Gas has consequently completed fewer large commercial projects in fiscal year 2022 than in fiscal year 2021.

Since the inception of its demand-side management programs, Vermont Gas has assisted its customers with completing 43,350 energy efficiency projects through programs covering equipment replacement, retrofit, and new construction. At the end of calendar year 2021, Vermont Gas completed the first year of the three-year energy efficiency utility performance budget. The budget was approved by the VPUC and represents just over US$15 million with savings at approximately 0.24 Bcf.

e) Competitive Position

In Vermont Gas' market, despite the recent volatility in the energy markets, natural gas has a competitive advantage when compared with other energy sources in the Residential, Commercial, and Industrial Markets. Electricity continues to evolve as a potential source of competition in the heating or domestic hot water markets due to the Vermont State's energy goals, which focus has shifted to renewable electrification and carbon reduction targets. Moreover, new renewable building ordinances in the cities of Burlington and South Burlington, in Vermont, may limit the use of fossil fuels for new construction in these regions in the future. Vermont Gas continues to monitor emerging heat pump technology and state policies driving electrification of various end-uses, which may change the competitive landscape. Vermont Gas also continues to explore additional offerings to its own customers, including new water heating technology.

f) Climate Change

i. Climate Change Risks and Opportunities

This information is presented in Item 4.1.1.6 a) *Climate Change Risks and Opportunities.*

ii. GHG Emissions Scenarios over the 2030 and 2050 Horizons

This information is presented in Item 4.1.2.1 g) ii. *GHG Emissions Scenarios over the 2030-2050 Horizons.*

iii Sustainability of Vermont Gas' Business Model

Vermont Gas has proactively adopted a strategy to transform its operations so as to make its in-house activities and energy distributions carbon neutral by 2050, in line with the State of Vermont's GHG emission reduction requirements. Vermont Gas has steadily expanded its weatherization efforts, added to its suite of decarbonized in-home services, and is establishing a portfolio of low- and no-carbon alternative fuels to transform how its customers warm their homes and businesses.

To achieve its Climate Plan benchmarks, Vermont Gas' innovation is focused on three key areas:

- Expanding weatherization and energy efficiency accelerating access to affordable weatherization services: Vermont Gas has increased weatherization rebates and incentives available to income-qualified Vermonters and is assessing ways to ensure these funds go to customers with the highest energy burden. Vermont Gas is one of several Vermont utilities that is participating in a pilot project to offer its customers funding opportunities for comprehensive weatherization improvements using the tariffs available under the Weatherization Repayment Assistance Program (WRAP).
- Launching renewable in-home solutions: Vermont Gas is developing renewable, in-home heating technologies for its customers. It was the first natural-gas-only distributor of the American Gas Association to offer electric heat pump water heaters. Vermont Gas is testing the installation of hybrid heating systems that integrate forced air furnaces with centrally ducted heat pump technology. Vermont Gas is also testing geothermal energy systems for commercial and multi-family housing applications.
- Growing the alternative energy supply: Vermont Gas is steadily increasing the renewable energy supply of its system. It develops biomethane RNG projects in Vermont, and oversees the development of green hydrogen, district energy loops, and networked geothermal energy for commercial purposes.

Achieving Vermont Gas' Climate Plan outlined is consistent with a GHG emission reduction pathway as described in the Sustainable Development Scenario or the Delayed Action Scenario, described in Item 4.1.2.1 g) ii. *GHG Emissions Scenarios over the 2030-2050 Horizons*. Vermont Gas has set specific goals that are equal to or greater than those set through the GWSA that was adopted and came into force in 2020. This Act was adopted in response to Vermont's concerns over climate change and the magnitude of what must be done to reduce GHG emissions and prepare for the effects of climate change on Vermont's landscape. In this context, this Act requires the State of Vermont to reduce GHG emissions to 26% below 2005 levels by 2025, 40% below 1990 levels by 2030 and 80% below 1990 levels by 2050.

Over the past years, global climate discussions and government commitments have begun to take greater account of new scenarios aligned with pathways to limit temperature rise to 1.5°C or less compared to the pre-industrial era. To reflect this reality, Vermont Gas uses a scenario in the range of pathways to be used to assess its climate resilience. It is important to clarify that for the moment, neither Vermont nor the United States have adopted climate targets to align with a pathway to limit the temperature rise to 1.5°C or less. Vermont Gas is aware that additional emission reductions would have to be achieved, particularly in the next ten years, if Vermont were to adopt a more restrictive GHG emission reduction pathway than those limiting global warming to 2°C or less.

Vermont Gas is revisiting even more aggressive targets to accomplish GHG emission reductions. Vermont Gas set the following:

- Contribute to Vermont's goal of reducing GHG emissions by at least 40% below 1990 levels by 2030.
- Achieve a carbon neutral energy supply by 2050.

iv. Climate Change Risk Identification and Management Practices

This information is presented in Item 4.1.1.6 d) *Climate Change Risk Identification and Management Practices.*

v. <u>Governance as related to Climate Change Risks and Opportunities</u>

Vermont Gas is regulated by the VPUC, and governed by Vermont Gas Board, which exerts strategic influence on the business to ensure its resilience and maintenance of the foundational values of safety and economic accessibility for its customers. Vermont Gas is led by its President and Chief Executive Officer. Its corporate governance structure is comprised of the Vermont Gas Board and an executive team.

The Vermont Gas Board reviews and approves Vermont Gas' annual strategic plan, key performance indicators ("KPIs") and major initiatives, and provides general advice and guidelines to Vermont Gas' executive team. The Vermont Gas Board currently has an audit committee and a human resources and compensation committee, which meet regularly to review Vermont Gas' performance and fulfill other Vermont Gas Board responsibilities.

The audit committee is responsible for providing guidance to management and making recommendations to the full Vermont Gas Board on all financial and accounting issues. Specifically, they are responsible for risk management review, including reviewing climate related risks.

The human resources and compensation committee is responsible for corporate performance plans and awards inclusive of reviewing climate related goals around carbon reduction.

The executive team manages strategic matters and presents key matters to the Vermont Gas Board for review and, as needed, for approval. Updates to Vermont Gas' Climate Plan are presented and reviewed in depth by the Vermont Gas Board.

4.2 Natural Gas Transportation

In Canada, interprovincial transportation activities and transportation activities beyond the limits of any province are regulated by the CER; in the United States, interstate transportation activities are regulated by the FERC. Énergir, L.P. owns financial interests in three natural gas transportation enterprises, namely TQM, Champion Pipe Line Corporation Limited and PNGTS.

TQM

Énergir, L.P. owns a 50.0% indirect interest in TQM, which operates a gas pipeline in Quebec that connects upstream with that of TCPL and downstream with that of PNGTS and the Énergir, L.P. system. Its activities are regulated by the CER.

In February 2022, the CER approved a (multiyear) rate agreement for TQM covering a two-year period. Under this agreement, annual rates are calculated using a formula that includes a fixed cost component and a cost component that is fully recoverable from or repayable to customers. Under this method, TQM can determine the optimal capital structure that would better reflect its economic reality and business risks.

Additional information on the regulatory framework of TQM can be found in section D) *Segment Results* on pages 24 and 25 of the 2022 MD&A.

Champion Pipe Line Corporation Limited

Champion Pipe Line Corporation Limited, a wholly owned subsidiary of Énergir, L.P., operates two gas pipelines that cross the Ontario border and supply Énergir, L.P.'s distribution network in northwestern Quebec. Its activities are regulated by the CER with respect to revenue determination, tolls, construction and operation of its network. Its rates are based on the annual cost of service, which includes a specified rate of return on equity as well as operating expenses, taxes and amortization. The deemed equity component is established at 46.0% for fiscal year 2022 (the same as for fiscal year 2021); its authorized rate of return was 8.32% for fiscal year 2022 (the same as for fiscal year 2021).

PNGTS

Énergir, L.P. owns a 38.3% indirect interest in the PNGTS pipeline, which starts at the Quebec border and extends to the suburbs of Boston. The activities of PNGTS are regulated by the FERC. Its rates are based on its cost of service, which includes a rate of return. Accordingly, in February 2015, the FERC approved PNGTS's rates, which are valid until a request for review is filed. However, when it deems it appropriate, PNGTS may negotiate agreements with specific customers that provide for a lower rate than the one approved by the FERC.

Additional information on the regulatory framework of TQM and the network reinforcement projects of TQM and PNGTS can be found in section D) *Segment Results* on page 24 and 25 of the 2022 MD&A.

4.3 Electricity Production

This segment consists of the non-regulated electricity production activities related to Wind Farms 2 and 3 and Wind Farm 4.

4.3.1 Wind Farms in Quebec

Wind Farms 2 and 3:	**WIND FARMS LOCATED ON THE PRIVATE LANDS OF THE SEIGNEURIE DE BEAUPRÉ** IN PARTNERSHIP WITH ÉNERGIR DEVELOPMENT AND BORALEX	Wind Farm 4:
126 WIND TURBINES **272 MW** OF INSTALLED CAPACITY		**28** WIND TURBINES **68 MW** OF INSTALLED CAPACITY

Wind power is one of the cleanest forms of energy as it produces no air emissions. It is sought after for its benefits, and is also complementary to hydroelectricity, because it serves as a back-up energy source that often reaches its maximum potential during periods of extreme cold and high winds.

To promote energies that reduce the environmental footprint, while also encouraging regional economic development, Énergir, L.P. and Énergir Development decided to invest in wind power production through the deployment of wind farms, particularly Wind Farms 2 and 3 and Wind Farm 4.

Beaupré Éole (in which Gaz Métro Éole and Valener Éole hold, respectively, a 51.0% and 49.0% interest) and Boralex are equal-share partners in two wind farms with an installed capacity of 272 MW on private lands of the Seigneurie de Beaupré, namely Wind Farms 2 and 3. All of the electricity generated is sold to Hydro-Québec under 20-year contracts with expiry dates between 2033 and 2034.

Beaupré Éole 4 (in which Gaz Métro Éole 4 and Valener Éole 4 hold, respectively, a 51.0% and 49.0% interest) and Boralex are equal-share partners in a third wind farm with an installed capacity of 68 MW on private lands of the Seigneurie de Beaupré, namely Wind Farm 4. All of the electricity generated is sold to Hydro-Québec under a 20-year contract

Additional information regarding Wind Farms 2 and 3 and Wind Farm 4 can be found in section D) *Segment Results* on page 25 of the 2022 MD&A.

On April 19, 2022, Énergir Inc. announced a partnership with Boralex and Hydro-Québec for the development of three wind power projects of 400 MW each on Seigneurie de Beaupré land. The projects will be implemented by Énergir Development, an affiliate to which the relevant development rights were transferred. If these projects are completed, the power generated will be purchased by Hydro-Québec. The goal of these projects is to propose concrete and promising solutions for a better energy future and to contribute to the development of renewable energy sources.

4.4 Energy Services, Storage and Other

4.4.1 Energy Services and Other

Énergir, L.P., through its subsidiaries, (i) sells natural gas as fuel for the heavy transportation market; (ii) continues to develop LNG marketing and production activities and to market CNG; (iii) offers natural-gas-powered appliance sales, leasing and maintenance services (until June 30, 2022); and (iv) operates the Montréal Thermal Plant, which supplies heat and air conditioning to the downtown area. The activities related to energy services are not regulated.

4.4.1.1 LNG

Énergir, L.P., through its subsidiary Gaz Métro LNG, is engaged in the development of LNG production and commercialization activities. Gaz Métro LNG's goal is to structure the LNG offer and ensure the marketing of the LNG produced using the LSR Plant's infrastructure. The various initiatives of Gaz Métro LNG include:

- developing a market for LNG as marine fuel;
- using LNG as an alternative to fuel oil or propane in the industrial and mining markets;
- selling LNG to a U.S. broker that then resells it to customers during peak periods; and

- developing the U.S. market: canvassing for new customers and maintaining existing contractual relations.

The objective of Transport Solutions, a wholly owned subsidiary of Énergir, L.P., is to develop the market for natural gas (both compressed and liquefied) as a fuel in the heavy transportation market and as an alternative to diesel fuel. It is Quebec's leader in this field, offering integrated LNG refuelling services in the industrial, road and maritime sectors. It also provides industrial customers LNG equipment maintenance services. Transport Solutions also plays a key role in the operation of LNG refuelling stations for the transportation industry between Lévis and Mississauga.

4.4.1.2 Énergir Management

On June 30, 2022, Énergir Management sold some of its assets and liabilities so as to divest itself of a portion of its operations. Since this sale, Énergir Management no longer offers a range of products and services associated with the installation, sale, rental, maintenance and repair of natural gas equipment. For more on this transaction, see section D) *Segment Results* of the 2022 MD&A.

Énergir, chaleur et climatisation urbaines s.e.c., an indirect wholly owned subsidiary of Énergir Management, owns and operates three separate steam, hot water and cool water networks that are used to meet the heating, hot water and air conditioning needs of office towers, shopping centres, hotels, railroad stations, campuses and prestige apartments. Its network extends over 4.8 kilometres and services 1.8 million m^2 of commercial area in downtown Montréal.

4.4.2 Storage

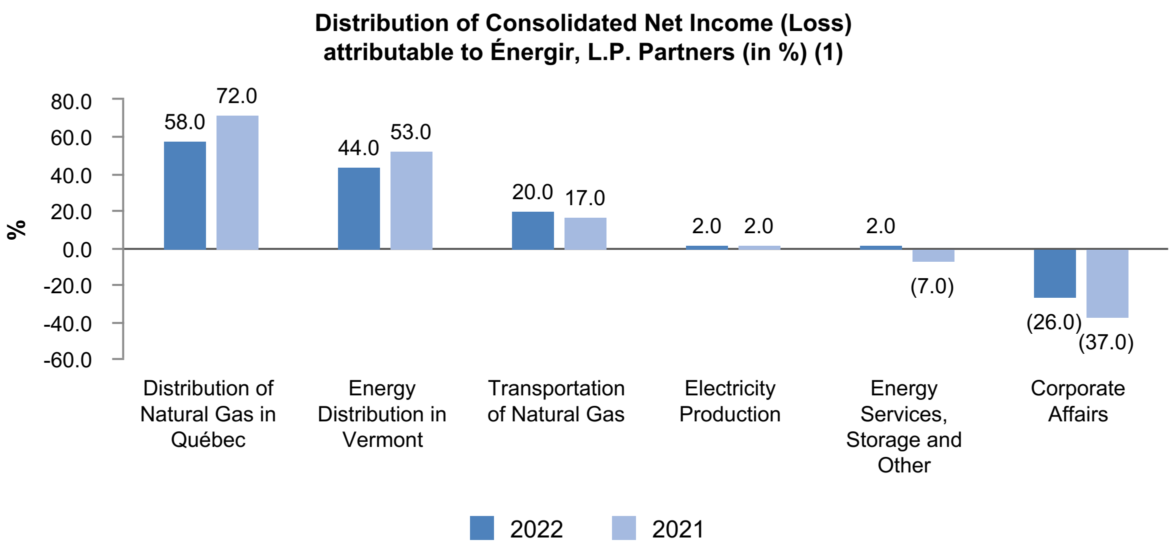
Énergir, L.P. owns an indirect interest in Intragas, whose main activity is underground natural gas storage. This activity fits within Énergir, L.P.'s overall mission, as natural gas storage is an integral part of its supply chain. The respective ownership interests of Énergir, L.P. and ENGIE, the other co-owner of Intragas, range from 40.0% to 60.0%, depending on the entities that make up Intragas.

Intragas, whose rates are approved by the Régie, operates the only two underground natural gas storage facilities in Quebec in the service area of Énergir, L.P., which is Intragas' only customer. Intragas sets its rates using the cost-of-service method.

4.5 Corporate Affairs

Among other things, this segment includes all of Énergir Inc.'s activities that cannot be directly attributed to other sectors, such as the costs incurred to finance the interests held and the development costs of various projects.

4.6 Consolidated Net Income by Business Segment



(1) Consolidated net income attributable to the partners of Énergir, L.P. for fiscal year 2022 included a $26.8 million unfavourable impact related to adjustments excluded from ongoing operations. The adjustments' amount is explained by a change in the tax treatment of the depreciation of investments in information technology development ($13.8 million), Énergir Management's disposal of some of its assets and liabilities ($8.6 million), and the writing-off of assets associated with the implementation of a customer information system ($4.4 million). For more information on these adjustments, see the 2022 MD&A. Had it not been for these items, the distribution of

consolidated net income attributable to the partners of Énergir, L.P. for fiscal year 2022 would have been as follows: Distribution of Natural Gas in Quebec, 57.0%; Distribution in Vermont, 41.0%; Transportation of Natural Gas, 18.0%; Electricity Production, 2.0%; Energy Services, Storage and Other, 5.0%; Corporate Affairs, -23.0%.

ITEM 5 HUMAN RESOURCES MANAGEMENT

As at September 30, 2022, Énergir, L.P. had, on a consolidated basis, 2,328 regular and temporary employees. The following table provides specific information on employees, broken down by segment.

Segment	Number of employees	Number of employees governed by a collective agreement	Number of collective agreements
Energy Distribution			
➔ Énergir, L.P.	1620	909	3
➔ Green Mountain	522	292	1
➔ Vermont Gas	132	54	1
Natural Gas Transportation(1)	0	0	0
Electricity Production(2)	0	0	0
Energy Services, Storage and Other(3)	48	22	2
Corporate Affairs	6	0	0
Total	**2,328**	**1,277**	**7**

(1) This segment has no employees owing to the existence of services agreements.
(2) This segment has no employees owing to the existence of service contracts for the wind farms in Quebec.
(3) This segment has seen the number of employees drop as compares to the number indicated for fiscal year 2021 owing to the fact that on June 30, 2022, Énergir Management disposed of some of its assets and liabilities so as to divest itself of a portion of its operations. Since this sale, Énergir Management has no employees, but a service agreement instead.

Énergir, L.P. is party to three collective agreements. The collective agreement for office workers affiliated with the SEPB-Québec union (which is itself affiliated with the Fédération des travailleurs et travailleuses du Québec (F.T.Q.)) was renewed on December 11, 2017, effective retroactively to September 1, 2015, and expired on August 31, 2020. Negotiations to renew began in January 2022. The collective agreement for sales representatives, who are also affiliated with the SEPB-Québec union, was renewed on September 18, 2018, and expired on September 30, 2021. Negotiations to renew will begin once negotiations to renew the collective agreement for office workers have been completed. The collective agreement for blue collar workers, who are affiliated with the Confédération des syndicats nationaux (CSN), was renewed on November 20, 2021, effective retroactively to October 1, 2019, and will be expiring on September 30, 2024.

The collective agreement for the unionized employees of Green Mountain was renewed on January 1, 2018, and will be in effect until December 31, 2022. The collective agreement for the unionized employees of Vermont Gas was renewed on June 1, 2018, and will be in effect until May 31, 2023.

The businesses of the Energy Services, Storage and Other segment are party to two collective agreements. In the case of the first collective agreement, the validity period is April 1, 2022 to March 31, 2026. A second collective agreement was renewed from June 1, 2019 until December 31, 2021, with an extension until December 31, 2023.

Énergir, L.P., its subsidiaries and joint ventures maintain good relations with their various unions and representatives. Management is of the opinion that relations with its employees are good. A survey on employee mobilization was conducted in September 2022 to measure progress since the last survey, conducted in September 2021. The results remain positive, showing employees to be committed and robust organizational health in a culturally evolving context involving, among other things, a transition to hybrid work for a majority of workers. In fiscal year 2022, Énergir, L.P. conducted a total of ten surveys to see whether its employees are mobilized and doing well, as well as to check their level of commitment and sense of belonging.

Énergir, L.P. wants to provide a discrimination-free workplace and has initiated an awareness campaign to ensure that everyone adopts non-discriminatory attitudes, language and practices that are free of unconscious bias. In addition, the talent acquisition process has been implemented on an ongoing basis, with improvements having been made in 2021 to further efforts to ensure the representation of women, particularly in non-traditional occupations, and more specifically in positions involved in the operation of the gas system.

Énergir, L.P.'s equity, diversity and inclusion action plan, inspired by the best practices in the field and launched in the fall of 2020, unfolded over the course of the last fiscal year. More specifically, for fiscal year 2022, all actions provided for in the action plan were successfully carried out. For example, the Diversity, Equity and Inclusion in Employment Policy was approved by the Board on August 4, 2022; a strategic diversity, equity and inclusion ("**DEI**") map, consisting of a plan of action and corporate governance, was developed; and an overall portrait of diversity (addressing, among other things, gender and visible minority status) was prepared for all Énergir, L.P. workers. An analysis was performed by an external firm offering DEI expertise to compare Énergir, L.P.'s practices with best DEI practices and to analyze the variances using that firm's DEI maturity model. In September 2022, training on unconscious bias was offered to all managers. This training will be extended to all Énergir, L.P. workers in fiscal year 2023.

Énergir, L.P. also adopted a general psychological health plan that includes, among other things, a rehabilitation program, a psycho-social risk assessment process and an employee and family assistance program tailored to their needs.

In fiscal year 2020, Énergir, L.P. completed a pay equity audit under the *Quebec Pay Equity Act*, which requires employers to demonstrate that positions held by women are treated equally to those held by men, in connection with the pay equity exercise. In fiscal year 2021, Énergir, L.P. completed the pay equity exercise. The analyses revealed that no adjustment was required. The various pay equity committees also concluded that pay equity has been maintained over the years and that Énergir, L.P., together with its committees, had implemented an efficient pay equity maintenance process that precluded any sexist bias.

The key to the success of Énergir, L.P., its subsidiaries and joint ventures lies partly in the specialized skills and knowledge required for operating and maintaining natural gas and electricity distribution systems. Such skills and knowledge are currently available; however, to protect themselves against the risk of future shortages in such specialized job positions, due principally to the increasing rate of planned retirements, Énergir, L.P. and some of its subsidiaries and joint ventures offer competitive direct compensation and benefit programs as well as the training needed to maintain and develop skills. Énergir, L.P. is certified for the quality of its contribution to workforce skills development pursuant to the *Regulation respecting the exemption applicable to a holder of a training initiative quality certificate.* Moreover, Énergir, L.P.'s École de technologie gazière in Boucherville, Quebec (which is an in-house training centre that dispenses gas technology education to the gas industry's entire workforce, including to an outside clientele) continues to help prepare succession in Quebec's gas industry and its development.

For more than 15 years, Énergir, L.P. has also been implementing a succession plan to ensure the transfer of skills as its employees retire. This succession plan is updated annually. This yearly exercise enables Énergir, L.P. to evaluate its vulnerability to future shortages in some specialized trades and implement action plans that are also monitored on an annual basis. Some of Énergir, L.P.'s subsidiaries and joint ventures also have a succession plan with a similar objective.

ITEM 6 FINANCIAL INFORMATION

6.1 Énergir Inc.

6.1.1 Consolidated financial data

The consolidated financial data for the fiscal years ended on September 30, 2022 and 2021 can be found in the 2022 MD&A, which is to be read in conjunction with the 2022 Financial Statements, which are available on the SEDAR website at www.sedar.com under the profile for Énergir Inc.

6.1.2 Declaration of dividends

For the past three fiscal years, Énergir Inc. declared to its shareholder the following dividends in accordance with the amount of cash available for that purpose:

	Fiscal years ended September 30		
	2022	**2021**	**2020**
Dividends declared to the shareholder (in millions of $)	99.0	45.5	326.5[1]

[1] In fiscal year 2020, Énergir Inc. paid a special dividend of $220.0 million taken out of the proceeds of the disposition of all shares held in Enbridge.

Noverco has undertaken to maintain Énergir Inc.'s equity at no less than $10.0 million as long as the subordinated debentures issued by Énergir Inc. remain outstanding. The five series of subordinated debentures totalling $892.8 million will mature in 2052. The interest rates on all series of subordinated debentures are adjusted on October 1 of each year based on a pre-established formula.

6.2 Énergir, L.P.

6.2.1 Income distribution

As explained under Item 1.2.3.4 *Distribution Practice*, subject to satisfaction of the financial ratios set out in the trust deeds, the credit agreement and the note purchase agreements (as more fully described under Item 10.2.4.1 *Financial Contracts (Énergir Inc. and Énergir, L.P.)*), Énergir, L.P. intends to continue to distribute substantially all of its net income for a given fiscal year, in accordance with its past practice, and the Limited Partnership Agreement provides that Énergir, L.P. will distribute not less than 85.0% of its net income, excluding non-recurring items, subject to certain exceptions. In principle, distributions are made on the first business day following the end of a calendar quarter, i.e., the first business day of January, April, July and October of each year.

Énergir, L.P. occasionally reviews the level of its quarterly distribution in light of anticipated changes in net income, which largely depends on changes in the rate of return allowed by the Régie and other regulatory bodies, as well as on the profitability of its non-regulated activities.

The following table shows the distributions declared to Énergir, L.P.'s partners over the last three fiscal years:

	Fiscal years ended September 30		
	2022	2021	2020
Distributions declared to the partners (in millions of $)	225.67	543.47[(1)]	206.15

(1) The distributions declared in fiscal year 2021 included four distributions to Énergir, L.P.'s partners totalling $337.3 million paid as part of the October 1, 2020 sale, to Énergir Solutions (US) Inc., of the common shares held by NNEEC in Standard Solar. The amount of regular distributions stands at $206.2 million for fiscal year 2021.

6.2.2 Restrictions on Distributions and Issuance of Long-Term Debt under the Deeds Creating and Governing the Long-Term Debt

The deeds and agreements creating and governing Énergir, L.P.'s long-term debt, or long-term debt for which Énergir, L.P. is responsible, impose certain restrictions on the distribution of earnings and the issuance of long-term debt by Énergir, L.P. Under such deeds and agreements, which define the expressions "aggregate capitalization" and "long-term debt":

i. Énergir, L.P. may not make any such distribution if, after giving effect thereto, Énergir, L.P.'s aggregate long-term debt would exceed 75.0% of its aggregate capitalization;

ii. Énergir, L.P. may not issue, assume or guarantee long-term debt if all such long-term debt issued, assumed or guaranteed by Énergir, L.P. and outstanding on the date of the proposed issuance, assumption or guarantee would exceed 65.0% of the aggregate capitalization of Énergir, L.P. on that date, after giving effect to the issue, assumption or guarantee and the receipt and allocation of the proceeds therefrom; and

iii. Énergir, L.P. may not issue, assume or guarantee long-term debt if earnings available for payment of interest charges during any period of 12 consecutive months selected by Énergir, L.P. out of 18 such months preceding the date of the proposed issuance, assumption or guarantee of the new long-term debt would be less than one and one-half times the sum of the annualized interest charges on all long-term debt issued or guaranteed by Énergir, L.P. outstanding at the date of such proposed issuance, assumption or guarantee and the annualized interest charges on the long-term debt proposed to be issue, assumed or guaranteed.

Énergir, L.P. calculates these ratios on the basis of its non-consolidated financial statements.

6.3 Financial Management

Énergir, L.P.'s financial strength depends, among other things, on the availability of natural gas at competitive prices, customer demand, the regulatory framework and the capital structure. Its financial health also depends on the ability of Énergir, L.P. and Green Mountain to earn the return allowed by their respective regulators. These issues have already been discussed in Item 4 *NARRATIVE DESCRIPTION OF ÉNERGIR, L.P.'S FIVE MAIN BUSINESS SEGMENTS.*

Historically, given certain legislative restrictions, the financing strategy consisted of having Énergir Inc. borrow on capital markets and then lend the borrowed amounts to Énergir, L.P. under identical conditions. Given that such restrictions no longer exist, the financing strategy has been reassessed, and Énergir, L.P. amended its deed of trust during the quarter ended December 31, 2021 so that it could finance itself directly without Énergir Inc.'s intervention.

Loan agreements in effect as at September 30, 2022

On July 13, 2022, Énergir Inc. and Énergir, L.P. entered into a new credit agreement with their bank consortium. The agreement features a renewable guaranteed credit facility of $800.0 million that expires on July 13, 2027. Subject to the lenders' approval, the expiry date of this credit agreement may be extended annually for one year. This credit agreement replaces the one entered into on March 2, 2012 by Énergir Inc. as borrower and by Énergir, L.P. as surety. As part of the change in financing strategy, Énergir, L.P. became the only borrower under the terms of the credit agreement starting in September of 2022. This agreement has a universal hypothec on the assets of Énergir, L.P. The terms of the credit agreement are similar to those in the previous agreement. Concurrently with the conclusion of this credit agreement, Énergir, L.P. issued an information circular for the issuance of short-term notes (also called commercial papers) up to an amount of $800.0 million. These notes are issued taking into account Énergir, L.P.'s financial imperatives and are backed by the credit agreement described above.

On August 18, 2021, Green Mountain replaced its US$150.0 million credit facility entered into with KeyBank National Association and a syndicate of lenders by a new US$175.0 million credit facility maturing on August 18, 2024. This credit facility was entered into with KeyBank National Association and People's United, and contains a US$25.0 million accordion facility. In fiscal 2022, Green Mountain activated this accordion facility to increase its available credit from US$175.0 million to US$195.0 million until September 2022.

Private placements during the fiscal year ended September 30, 2022

On September 27, 2022, after a series of secured senior notes totalling $167.0 million matured in May of 2022 , Énergir, L.P. issued $200.0 million in first mortgage bonds by way of private placement. These bonds yield interest at an annual rate of 4.67%, will mature on September 27, 2032, and are guaranteed by a hypothec on the assets of Énergir, L.P. The proceeds of the issuance were used to repay existing debts and for the general purposes of Énergir, L.P.

On September 23, 2022, Green Mountain issued US$25.0 million in first mortgage bonds. These bonds will be maturing in October of 2052 and yield interest at an annual rate of 5.0%. The proceeds of the issuance were used to repay a portion of its credit facility.

On February 9, 2022, Énergir, L.P. issued $325.0 million in first mortgage bonds by way of private placement. These bonds yield interest at an annual rate of 3.04%, will mature on February 9, 2032, and are guaranteed by a hypothec on the assets of Énergir, L.P. The proceeds of the issuance were used to repay existing debts and for the general purposes of Énergir, L.P.

ITEM 7 LEGAL PROCEEDINGS

Additional information regarding litigation involving Énergir, L.P. can be found in section K) *Additional Information* on page 46 of the 2022 MD&A.

ITEM 8 MARKET FOR SECURITIES, CAPITAL STRUCTURES AND TRANSFER AGENT AND REGISTRAR

8.1 Market for Énergir Inc.'s securities

Although Énergir Inc.'s common shares are not listed on any stock exchange or equivalent market, it is a reporting issuer under securities legislation because it has issued first mortgage bonds on the capital markets.

8.2 Énergir Inc.'s capital structure

Énergir Inc. can issue an unlimited number of common shares without par value. As at September 30, 2022, 2,977,158 shares were issued and outstanding. Énergir Inc. can also issue one or more series of preferred shares, the votes, privileges, conditions and restrictions of which will be fixed by the Board. As at September 30, 2022, no such preferred shares had been issued.

8.3 Credit ratings

Énergir Inc. and Énergir, L.P. receive solid credit ratings from S&P and DBRS.

As at September 30		
Énergir Inc.	**2022**	2021
Corporate (S&P/DBRS)	**A/A**	A/A
First mortgage bonds/secured senior notes (S&P/DBRS)	**A/A**	A/A
Commercial paper (S&P/DBRS)	**-**	A-1(mid)/R-1(low)
Énergir, L.P.	**2022**	2021
Corporate (S&P/DBRS in 2022 - S&P in 2021)	**A/A**	A
First mortgage bonds (S&P/DBRS)	**A/A**	-
Commercial paper (DBRS)	**R-1(low)**	-

The rating agencies S&P and DBRS reconfirmed, in December of 2021 and April of 2022, respectively, the credit ratings assigned to Énergir Inc. In December, S&P also reconfirmed the corporate credit rating of Énergir, L.P. for 2021. Énergir, L.P. obtained credit ratings in fiscal year 2022 for the first mortgage bonds and for the commercial paper.

In August 2021, S&P increased the credit rating of Green Mountain from A- to A.

The corporate credit ratings assigned to Énergir Inc. and Énergir, L.P. by S&P and DBRS, and the ratings assigned to the first mortgage bonds and the commercial paper represent an assessment, by the credit rating agencies, of Énergir Inc. and Énergir, L.P.'s ability to meet their financial commitments. The ratings are based on certain assumptions with respect to Énergir, L.P.'s future return and capital structure that may or may not be realized.

S&P's ratings for long-term debt instruments range from a high of AAA to a low of D. Ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. According to S&P's rating system, debt instruments rated A are somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than debt instruments in higher-rated categories. However, the obligor's capacity to meet its financial commitments is still strong.

DBRS's ratings for long-term debt instruments range from a high of AAA to a low of D. The assignment of a "high" or "low" designation within each rating category indicates relative standing within that category. The absence of a "high" or "low" designation indicates that the rating is in the "middle" of the category. The "high," "middle" and "low" grades are not used for the AAA and D categories. According to DBRS's rating system, debt instruments rated A are characterized as satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength of entities having A-rated securities is less than that of entities having AA-rated securities. While A is a respectable rating, entities having securities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than entities having higher-rated securities.

S&P's ratings for Canadian commercial paper range from a high of A-1 to a low of D. A "high," "mid" or "low" designation may be assigned to A-1 ratings only. S&P's A-1 (mid) rating is the second highest of eight categories. According to S&P's rating system, commercial paper rated A-1 (mid) reflects the obligor's strong ability to meet its financial commitments.

DBRS's ratings for commercial paper range from a high of R-1 to a low of D. A "high," "middle" or "low" designation may be assigned to R-1 and R-2 ratings only. DBRS's R-1 (low) rating is the third highest of 10 categories. According to DBRS's rating system, commercial paper rated R-1 (low) is of satisfactory credit quality. The outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the borrower is normally of sufficient size to have some influence in its industry.

These credit ratings do not constitute recommendations to purchase, sell or hold positions and the rating agencies that gave them can change or withdraw them at any time.

Énergir, L.P. paid fees to S&P and to DBRS for surveillance services in relation to the ratings they assigned to the first mortgage bonds and commercial paper and in relation to the corporate ratings, based on their respective fee schedules. Over the course of the last two years, fees were paid by Énergir Inc. to S&P for rating assessment services. No other amounts were paid to DBRS in relation to any other services rendered to Énergir Inc. and Énergir, L.P. for the last two years.

8.4 Transfer agent and registrar

Computershare Trust Company of Canada is the transfer agent and registrar for the Énergir Inc. first mortgage bonds and secured notes. The main transfer register is maintained in Montréal, Quebec, Canada.

Énergir Inc. acts as registrar and transfer agent for the Units. The main transfer register is kept in Montréal, Quebec, Canada.

ITEM 9 DIRECTORS AND OFFICERS

9.1 Directors

The Directors of Énergir Inc. are appointed by Noverco, its sole shareholder, and hold office until the next annual meeting or until their replacements are appointed.

As of the date hereof, the Directors of Énergir Inc. are as follows:

<table>
<tr><td colspan="2">
Renaud Faucher
Quebec, Canada
Non-independent[1]
Director since March 10, 2014
Areas of Expertise
▪ Finance
▪ Engineering
▪ Accounting/Audit</td><td colspan="2">Mr. Renaud Faucher joined the CDPQ in 2006. He is currently Managing Director, Infrastructure, North America. Mr. Faucher holds a bachelor's in civil engineering from École Polytechnique de Montréal, an MBA from Concordia University and a DESS (specialized graduate diploma) in accounting from ESG-UQAM. He is a member of the Ordre des Ingénieurs du Québec, of the Ordre des CPA and of the Institute of Corporate Directors (ICD). From 1986 to 1990, Mr. Faucher worked, as an engineer, on the construction management of projects in Canada and Europe, including the Channel Tunnel project. From 1992 to 1998, Mr. Faucher worked on the management and financing of independent power plants across Canada. From 1998 to 2006, he held different positions within international subsidiaries of Hydro-Québec as Director Investments, Vice President Finance and Vice President Risk Management. In addition to sitting on the boards of various corporations of the CDPQ's corporate group, Mr. Faucher is a member of the compensation committee of Colonial Pipeline Company and the following boards of directors: Noverco (2014 and Chair of the board since 2015, prior to that from 2006 to 2009), Colonial Pipeline (2014), Southern Star Central Gas Pipeline (2018 and Chair of the board from 2019 to 2021), Énergir Development (Chair of the board since 2019), Valener Éole Inc. (2019), Valener Éole 4 Inc. (2019), Mercury Taiwan Holdings Limited (2021), Greater Changhua SE Holdings (2021) and Greater Changhua Offshore Wind Farm SE LTD (2021). From 2003 to 2021, he also sat on various boards of directors in the energy, pipeline, aviation and infrastructure sectors. Over the course of his career, he also sat on the human resources committees of several companies in the pipeline and health sectors.</td></tr>
<tr><td>Principal occupation</td><td colspan="3">Managing Director, Infrastructure, North America, CDPQ.</td></tr>
<tr><td colspan="3">Attendance at meeting during fiscal year 2022</td><td>Total compensation[2]</td></tr>
<tr><td>Board</td><td>5/5</td><td>100%</td><td rowspan="4">N/A</td></tr>
<tr><td>Executive Committee</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Audit Committee (chair)</td><td>5/5</td><td>100%</td></tr>
<tr><td>HR-CG Committee</td><td>5/5</td><td>100%</td></tr>
<tr><td colspan="4">Other reporting issuer directorships held as at the date hereof</td></tr>
<tr><td colspan="3">Nil.</td><td></td></tr>
</table>

(1) Mr. Faucher is chair of the board of Noverco, Énergir Inc.'s sole shareholder, and, as such, is not independent.
(2) The representatives of the CDPQ who sit on the Board have waived their compensation as directors of Énergir Inc. and as members of its committees.

Ghislain Gauthier

Quebec, Canada

Independent

Director since March 10, 2014

Areas of Expertise

- Finance
- Human Resources

A graduate in administration from the Université du Québec à Chicoutimi, Mr. Ghislain Gauthier is also a Chartered Financial Analyst (CFA). Following a few years with the Business Development Bank of Canada and Export Development Canada, Mr. Gauthier joined the CDPQ in 1982, where he worked primarily in private placements. While at the CDPQ, he has been responsible for the management and growth of a substantial North American and European portfolio of corporate securities in the energy and infrastructure sectors. From January 2010 to September 2013, he was Chief Investment Officer of Citi Infrastructure Investors in New York and was Chair of its Investment Committee. He is currently a member of the Board of Directors and of the Investment Committee of Fiera Infrastructure. Mr. Gauthier has been a director of many airport and infrastructure corporations, and has therefore had the opportunity to intervene in various aspects of human resource management.

Principal occupation	Advisor and Corporate Director		
Attendance at meeting during fiscal year 2022			**Total compensation**
Board (chair)	5/5	100%	$225,000
Executive Committee (chair)	N/A	N/A	
Audit Committee[(1)]	3/3	100%	
HR-CG Committee (chair)	5/5	100%	
OHS-Env. Committee (chair)[(2)]	5/5	100%	
Other reporting issuer directorships held as at the date hereof			
Nil.			

(1) Mr. Gauthier stepped down from the Audit Committee on February 24, 2022 and attended all of the Audit Committee meetings prior to that date.

(2) Mr. Gauthier was named chair of the OHS-Env. Committee on February 11, 2022.

Jean-Luc Gravel

Quebec, Canada

Independent

Director since August 7, 2014

Areas of Expertise

- Finance
- Human Resources
- Sustainable Development/ Environment

Mr. Jean-Luc Gravel has a master of business administration from the University of Ottawa and holds a bachelor of science from the Université de Sherbrooke. He served as Strategic Advisor to the President at the CDPQ from 2018 to 2020. He supported the President and Chief Executive Officer to steer CDPQ's orientations and design growth strategies. Mr. Gravel was Executive Vice-President, Equity Markets at CDPQ between 2009 and 2018. In this role, he developed strategies and explored new opportunities for all CDPQ's equity market activities. A Chartered Financial Analyst (CFA) and a Fellow of the Canadian Securities Institute, he began his career in the financial industry in 1982. He began as an analyst, and later held management positions in large financial institutions established in Montréal, including Nesbitt Burns, Newcrest Capital and TD Newcrest Securities. He has also been a financial reporter for the investment section of the newspaper Les Affaires. He worked at CDPQ for two years in the 1980s and later returned in 2004, where he held the position of Senior Vice-President, Canadian Equity, until 2009, overseeing a team of 25 portfolio managers and financial analysts. Mr. Gravel sits on the Board of Directors of First Eagle Holdings, the Bromont Environmental Advisory Committee, and the Investment Committee of Blue Bridge Wealth Management Inc. From 1995 to 2016, he was also a member of the boards of directors of financial corporations.

Principal occupation	Corporate Director		
Attendance at meeting during fiscal year 2022			**Total compensation**[(1)]
Board	5/5	100%	$104,000
OHS-Env. Committee	5/5	100%	
Other reporting issuer directorships held as at the date hereof			
First Eagle Holdings, Inc.[(2)]			

(1) In addition to his compensation as director of Énergir Inc. and member of the OHS-Env. Committee, Mr. Gravel received compensation as an invitee on the Investment Committee of Énergir, L.P., which is not a Board committee. For more information on the subject, see Item 10.1.6.3 *Director Compensation Table.*

(2) This corporation is listed on the U.S. Securities and Exchange Commission but is not a reporting issuer in Canada.

Éric Lachance
Quebec, Canada
Non-independent(1)
(member of Management)
Director since January 1, 2020
Areas of Expertise

- Finance
- Accounting/Audit

Mr. Éric Lachance became President and Chief Executive Officer on January 1, 2020. He holds a bachelor's degree in business, finance and economics from McGill University and has been a chartered financial analyst since 2000. He joined Énergir Inc. in January 2017 as Vice President, Finance, and was appointed Senior Vice President, Regulatory, IT, Logistics and Chief Financial Officer on June 1, 2018. From February 2000 to December 2016, he held various positions at the CDPQ, the last three years as Regional Director – Europe within its subsidiary, CDPQ Paris, where he led the team responsible for ensuring the supervision and valuation of the CDPQ's European infrastructure investment portfolio. In this role, he represented the CDPQ as a member of the boards and oversight committees of many infrastructure companies. Firmly committed to the energy transition, Mr. Lachance strives to think of energy not as a product, but as a service that must meet various needs as best as possible, notably that of moving toward a lower-carbon economy. He sees the metamorphosis of the energy world over the next 20 years as a source of challenge that will require creativity and adaptability. Since January 2020, he has been a member of board of directors of the Canadian Gas Association and of the Industries and Transportation division committee of Centraide Of Greater Montreal's campaign cabinet.

Principal occupation	President and Chief Executive Officer, Énergir Inc.		
Attendance at meeting during fiscal year 2022			**Total compensation**(2)
Board	5/5	100%	N/A
Executive Committee	N/A	N/A	
Other reporting issuer directorships held as at the date hereof			
Nil.			

(1) Mr. Lachance is President and Chief Executive Officer of Énergir Inc. and, as such, is not independent.
(2) The President and Chief Executive Officer does not receive any compensation for his services as a director.

Jean-Christophe Lincourt-Éthier
Quebec, Canada
Independent
Director since January 26, 2022
Areas of Expertise

- Finance
- Accounting/Audit

Mr. Jean-Christophe Lincourt-Éthier is currently Senior Director, Infrastructure, at the CDPQ, where he is responsible for the management of investments in North America in the energy sector and public transport. Mr. Lincourt-Éthier holds a bachelor's degree in business administration, specializing in finance and accounting, from HEC Montréal and is a member of the Ordre des CPA du Québec. He joined the CDPQ in 2012 and, from 2015 to 2018, he participated in the creation of the CDPQ Infra subsidiary and in the development of the Réseau express métropolitain ("**REM**"), a 67-km light rail metro in the greater Montreal area. From 2018 to 2021, he took over the financial operations of the REM in addition to sitting on the boards of directors of REM Commandité Inc., Réseau express métropolitain Inc. (as well as on the audit committee) and InfraMTL Inc. as an executive. Before joining the CDPQ, Mr. Lincourt-Éthier participated in the financing and completion of infrastructure projects at SNC-Lavalin Capital, including the Restigouche Hospital Center in New Brunswick, the Highway 407 Extension in Ontario and the McGill University Health Centre in Montreal. Since 2021, Mr. Lincourt-Éthier serves on the boards of directors of Noverco, Énergir Development, Valener Éole Inc. and Valener Éole 4 Inc. He has been sitting on the board of directors of Immeuble VDS Inc. (a subsidiary of CDPQ Infra) since 2022.

Principal occupation	Senior Director, Infrastructure, CDPQ		
Attendance(1) **at meeting during fiscal year 2022**			**Total compensation**(2)
Board	3/3	100 %	N/A
Audit Committee	3/3	100 %	
Other reporting issuer directorships held as at the date hereof			
Nil.			

(1) Mr. Lincourt-Éthier attended all meetings of the Board and of the Audit Committee after he was appointed director of Énergir Inc. on January 26, 2022.
(2) The representatives of the CDPQ who sit on the Board have waived their compensation as directors of Énergir Inc. and as members of its committees.

Mary G. Powell

Vermont, United States

Non-independent(1)

Director since November 21, 2019

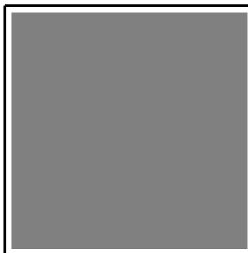
Areas of Expertise

- Human Resources
- Sustainable Development/ Environment

In 2021, Ms. Mary Powell became President and Chief Executive Officer of Sunrun Inc., the United State's leading home solar, battery storage and energy services company. Ms. Powell is a graduate of the Wharton Executive Education Program and is recognized as an energy visionary in the United States. From 2008 to 2019, Ms. Powell served as President and Chief Executive Officer for Green Mountain, where she positioned the company as a world leader in energy transformation. While CEO, she initiated and implemented a strategic and comprehensive restructuring of the company that dramatically transformed Green Mountain, thus becoming the backbone of a cultural transformation and service quality improvement. Under Ms. Powell's leadership, Green Mountain was the first utility in the world to become a member of B Corp, showing a commitment to use energy as a force for good. Prior to joining Green Mountain, Ms. Powell was Senior Vice President, Community Banking, at Keycorp from 1992 to 1997. She also held the positions of Director of Human Resources for the State of Vermont from 1989 to 1992 and of Associate Director of Operations at the Reserve Fund in New York from 1980 to 1989. Ms. Powell has received much recognition during her career, including, in 2018, being named one of the 25 Most Influential Women of the Mid-Market by CEO Connection. Conscious Capitalism Media also added her to its 2018 list of 30 World-Changing Women in Conscious Business. Ms. Powell currently serves on the boards of directors of CGI Inc. and Sunrun Inc. She also served as the Chair of CRIS, a special purpose acquisition company (SPAC) that took EVgo public. Ms. Powell was also Chair of The Solar Foundation and sat on the boards of directors of various corporations in the energy and insurance sectors.

Principal occupation	President and Chief Executive Officer, Sunrun Inc.		
Attendance at meeting during fiscal year 2022			**Total compensation**(2)
Board	5/5	100%	$92,000
OHS-Env. Committee	4/5	80%	
Other reporting issuer directorships held as at the date hereof			
CGI Inc.	Sunrun, Inc.(3)		

(1) Ms. Powell was President and Chief Executive Officer of Green Mountain, a material subsidiary of Énergir, L.P., until December 31, 2019, and, as such, is not independent.
(2) Ms. Powell is paid in U.S. dollars.
(3) This corporation is listed on the U.S. Securities and Exchange Commission, but is not a reporting issuer in Canada.



Marie-Pier St-Hilaire

Quebec, Canada

Independent

Director since February 24, 2022

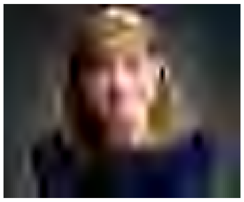
Areas of Expertise

- Finance
- Technology
- Human Resources

In 2000, Ms. St-Hilaire founded AFI Expertise, currently one of the corporate names of Groupe Edgenda inc., for which she has acted as president since 2017. In that role, she is reinventing the traditional world of organizational transformation consulting by placing skills development at the heart of business strategies. Ms. St-Hilaire holds a bachelor's degree in corporate management and an MBA (with a specialization in information technology) from Université Laval, and graduated from the Owner/President Management Program at Harvard Business School. In 2020, she became a certified business coach and started professionally accompanying other leaders in their growth processes. She inspires organizations to rethink their know-how and soft skills as well as adapt and grow in a thriving digital environment. She pursues the company's mission by bringing together technology and people to develop the full potential of individuals, teams, and organizations. She also shares her time and expertise as a speaker and volunteer. Over the past 20 years, she has been able to achieve her entrepreneurial vision and produce organic, continuous, and profitable growth for her company. She has also led several acquisitions, including that of Apprentx, which, with its B12 application, has consolidated the group's position as the Canadian leader in skills development. Ms. St-Hilaire currently sits on the boards of directors of Amerispa (since April 2022) and Entrepreneuriat Laval (since September 2021).

Principal occupation	President, Groupe Edgenda inc.		
Attendance(1) **at meeting during fiscal year 2022**			**Total compensation**(2)
Board	2/2	100 %	$52,667
Audit Committee	2/2	100 %	
Other reporting issuer directorships held as at the date hereof			
Nil.			

(1) Ms. St-Hilaire attended all meetings of the Board and of the Audit Committee after she was appointed director of Énergir Inc. on February 24, 2022.



Keri Sweet Zavaglia

New York, United States

Independent

Director since July 5, 2022

Areas of Expertise

- Law

Ms. Keri Sweet Zavaglia joined National Grid in the United States in 2006, one of the largest investor-owned energy companies in America serving more than 20 million people throughout New York and Massachusetts. Since 2019, she serves as General Counsel and, as such, is responsible for all corporate, commercial, governance, litigation, employment, finance and securities, real estate, and federal and state regulatory legal matters across the company's service territory. Ms. Sweet Zavaglia helps implement National Grid's vision of a fossil-free future while providing a safe, reliable and affordable service. Ms. Sweet Zavaglia earned her Juris Doctor degree from Temple University Beasley School of Law and holds a bachelor of arts in journalism, also from Temple University. Prior to this role, Ms. Sweet Zavaglia served as the Vice President, Performance and Strategy for National Grid's three New York operating companies (2015-2018) and as the Acting Vice President of Upstate New York Gas Operations (2014-2017). While in operations, Ms. Sweet Zavaglia was responsible for ensuring the safe and reliable operation of nearly 14,500 kilometres of gas pipelines and the maintenance and construction of assets serving a territory with more than 600,000 customers. Prior to joining National Grid in 2006, she served as an Assistant District Attorney in Philadelphia in the Repeat Offenders Unit (2002-2005). Ms. Sweet Zavaglia was recently added by the National Diversity Council to its 2022 Power 50 list, and was recognized as one of INvolve Heroes 100 Executives Role Models 2022, an initiative sponsored by Yahoo! Finance. She serves on the boards of directors of the Trinity Health of New York Hospitals (2022) and the United Way of Central New York (2022), and previously sat on the board of directors of St. Joseph's Health Hospital (2020 to 2022) and its foundation (2018 to 2020). Ms. Sweet Zavaglia is a member of Executive Women in Energy, and serves on the legal committees of multiple industry organizations. She chaired the American Heart Association's 2022 CNY Heart Challenge and serves as member of the Executive Leadership team.

Principal occupation	General Counsel, United States, National Grid

Attendance[1] at meeting during fiscal year 2022			**Total compensation[2]**
Board	1/1	100 %	$23,000
HR-CG Committee	1/1	100 %	

Other reporting issuer directorships held as at the date hereof
Nil.

(1) Ms. Sweet Zavaglia attended all meetings of the Board and of the HR-CG Committee after she was appointed director of Énergir Inc. on July 5, 2022.

(2) Ms. Sweet Zavaglia is paid in U.S. dollars.

<table>
<tr><td colspan="3">
Nathalie Viens
Quebec, Canada
Independent
Director since November 27, 2020
Areas of Expertise
▪ Engineering
▪ Sustainable Development/ Environment
▪ Technology</td><td colspan="2">Ms. Nathalie Viens is an Operating Partner supporting the global portfolio of the CDPQ's Infrastructure group. Ms. Viens has a bachelor's and master's degree in chemical engineering from École Polytechnique de Montréal. She has a professional engineering certificate for the province of Quebec and is also a certified project management professional (PMP) and a certified board member (ASC & C. Dir). Prior to joining the CDPQ in August 2020, Ms. Viens was Senior Vice-President of Operations for Eastern Canada at Veolia North America. In that role, she managed the activities related to energy and water, environmental solutions and services (ESS) and all oil regeneration and industrial cleaning activities. From 2015 to 2018, Ms. Viens was Vice-President responsible for activities related to the mining environment as well as mine and plant engineering for SNC-Lavalin's North American Mining and Metallurgy group. From 2000 to 2015, Ms. Viens led various projects and teams at Accenture: management of functional and operational teams, program management and major operational transformations, and integration of information and operational systems. During her career, Ms. Viens has held various management positions in large corporations, where she was responsible for service offices and operating plants, management (P&L) as well as support functions, including human resources. Ms. Viens currently sits on the following boards of directors: Noverco, Transportadora Associada de Gás S.A., Student Transportation of America, Plenary Americas, and FiBrasil. She is also President and Chair of the French Chamber of Commerce and Industry in Canada (CCIF).</td></tr>
<tr><td>Principal occupation</td><td colspan="4">Operating Partner, Infrastructure, CDPQ</td></tr>
<tr><td colspan="3">Attendance at meeting during fiscal year 2022</td><td colspan="2">Total compensation[1]</td></tr>
<tr><td>Board</td><td>5/5</td><td>100%</td><td colspan="2" rowspan="3">N/A</td></tr>
<tr><td>Audit Committee</td><td>4/5</td><td>80%</td></tr>
<tr><td>HR-CG Committee</td><td>4/5</td><td>80%</td></tr>
<tr><td colspan="5">Other reporting issuer directorships held as at the date hereof</td></tr>
<tr><td colspan="3">Nil.</td><td colspan="2"></td></tr>
</table>

(1) The representatives of the CDPQ who sit on the Board have waived their compensation as directors of Énergir Inc. and as members of its committees.

Positions and Offices Held During the Preceding Five Years

Over the past five years, all of the aforementioned Directors have had the principal occupation indicated opposite their names or have held various positions with the above-mentioned companies or their subsidiaries, predecessors or affiliated companies, with the exception of:

- Mr. Jean-Luc Gravel, who was Strategic Advisor to the President at the CDPQ from 2018 to 2020. As Vice President, he led the Equity Markets team at the CDPQ from 2009 to 2018.
- Ms. Mary Powell, who was President and CEO of Green Mountain until December 31, 2019, and who was appointed President and Chief Executive Officer of Sunrun Inc. on August 31, 2021;
- Ms. Keri Sweet Zavaglia who, from 2015 to 2018, was Vice-President, Performance and Strategy for National Grid in the New York State, and Interim Vice-President, Gas Operations in the north of New York State from 2014 to 2017; and
- Ms. Nathalie Viens who, from August 2018 to August 2020, was Senior Vice-President of Operations for Eastern Canada at Veolia North America. From 2015 to 2018, she was Vice-President of Sustaining Capital and Consulting Services for SNC-Lavalin's North American Mining and Metallurgy group.

Conflicts of Interest

Except as otherwise described herein, none of the directors whose name appears above is in a situation of conflict of interest.

Ms. Nathalie Viens, and Messrs. Renaud Faucher and Jean-Christophe Lincourt-Éthier, all employees of the indirect majority shareholder of Noverco, Ms. Keri Sweet Zavaglia, General Counsel for National Grid, as well as Ms. Mary Powell, President and Chief Executive Officer of Sunrun Inc., may be, or be perceived as being, in a situation of conflict of interest. Particularly, CDPQ, National Grid and Sunrun Inc. or any of their subsidiaries could find themselves in competition with Énergir, L.P. or one of its subsidiaries in some investment projects.

The CGEE Committee is responsible for overseeing and managing actual or potential conflicts of interest of officers and directors. Moreover, the Énergir Inc. By-Laws require a director to disclose any actual or potential conflict of interest, to abstain from any deliberations on any matter that could affect his or her interest, to avoid influencing a vote thereon and to abstain from voting thereon. These rules are strictly followed. For more information on the management of conflicts of interest, please refer to Item 10.2.1.3 *Organizational Ethics*.

9.2 Executive Officers

As of the date hereof, the position, province and country of residence of Énergir Inc.'s executive officers are as follows:

Name, province/state and country of residence	Current position with Énergir Inc.
Éric Lachance Quebec, Canada	President and Chief Executive Officer
Claudine Beaudet Quebec, Canada	Vice President, Employees and Culture
Charles Brenn Quebec, Canada	Vice President, Information Technologies
Étienne Champagne Quebec, Canada	Vice President, Development and Major Projects
Marc-André Goyette Quebec, Canada	Vice President, Strategy, Finance and Regulation
Frédéric Krikorian Quebec, Canada	Vice President, Sustainability, Public and Government Affairs
Mathieu Lepage Vermont, United States	Chief Financial Officer
Nathalie Longval Quebec, Canada	Assistant Vice President, Legal Affairs
Renault-François Lortie Quebec, Canada	Vice President, Customers and Gas Supply
Stéphane Santerre Quebec, Canada	Vice President, Operations
Stéphanie Trudeau Quebec, Canada	Executive Vice President, Quebec

All of the aforementioned executive officers hold or have held the position indicated opposite their name or another position with Énergir Inc. or its Affiliates during the past five years, with the exception of:

- Mr. Charles Brenn who, from June 2018 to March 2019, was Vice President, Clients and Product Development at Sogema Technologies Inc. Mr. Brenn was also Vice President, Software and Product Development at Outbox Technology Inc. from June 2015 to June 2018.

9.3 Cease Trade Orders, Bankruptcies, Penalties or Sanctions

The directors and executive officers have made no statement concerning the corporate cease trade orders or bankruptcies of public companies of which they are or have been a director or officer within the 10 years preceding the date hereof.

ITEM 10 ADDITIONAL INFORMATION

As explained under Item 3 *NARRATIVE DESCRIPTION OF ÉNERGIR INC.'S CORE BUSINESS*, Énergir Inc. acts as general partner of Énergir, L.P., which, therefore, pays the fees and compensation related to the directors and officers of Énergir Inc.

10.1 Report on Executive Officer and Director Compensation

10.1.1 Explanatory Note on Named Executive Officer Compensation Disclosure

In accordance with section 1.2 of Form 51-102F6, the Named Executive Officers of Énergir Inc. are: (i) the President and Chief Executive Officer; (ii) the Chief Financial Officer; and (iii) the three other most highly compensated executive officers of Énergir Inc. (including its subsidiary Green Mountain) for the fiscal year ended September 30, 2022, whose total compensation for that fiscal year was, individually, more than $150,000 (the "**Named Executive Officers**").

Under Form 51-102F6, Énergir Inc. is required to disclose the compensation of the President and Chief Executive Officer of Green Mountain, Ms. Mari McClure, as one of the Named Executive Officers for disclosure purposes in this Annual Information Form. Ms. McClure received compensation based on Green Mountain's executive officer compensation policy and the Green Mountain Board is responsible for determining principles underlying the executive officer compensation policy. She is paid in U.S. dollars by Green Mountain.

The following table shows the five Named Executive Officers for the fiscal year ended on September 30, 2022:

Company	Éric Lachance	Stéphanie Trudeau	Renault-François Lortie	Mathieu Lepage	Mari McClure
	Énergir Inc.			Green Mountain	
Positions	President and Chief Executive Officer	Executive Vice President, Quebec	Vice President, Customers and Gas Supply	Chief Financial Officer, Énergir, L.P. and Vice President, Chief Financial Officer and Treasurer of Green Mountain	President and Chief Executive Officer
Basis of compensation	Énergir, L.P.'s Compensation Policy for Senior Executives			Green Mountain's executive officer compensation policy(1)	
Compensation policy	Principles determined by the Board			Principles determined by the Green Mountain Board(1)	
Currency Compensation	Canadian			U.S.	

(1) Although Mr. Lepage is the Chief Financial Officer of Énergir Inc., he is compensated in accordance with Green Mountain's compensation policy. For further details, please see Item 10.1.3.1 *Compensation Policies for Named Executive Officers.*

10.1.2 Report on Named Executive Officer Compensation

10.1.2.1 Human Resources and Social Responsibility Committee

a) Compensation Committees

Énergir, L.P.

The members of the HR-SR Committee are independent, in accordance with the independence requirements of Regulation 52-110, with the exception of Mr. Renaud Faucher. As a result of their education and professional background, including (in some cases) having served on human resources and corporate governance committees of other corporations, all members of the HR-SR Committee have the experience needed and the skills to enable the HR-SR Committee to make recommendations to the Board on the suitability of Énergir, L.P.'s compensation policies and practices. For more information on the qualifications and experience of the HR-SR Committee members, please refer to their biographies in Item 9.1 *Directors*.

The HR-SR Committee has four members: Renaud Faucher, Ghislain Gauthier (Chair), Keri Sweet Zavaglia and Nathalie Viens.

The mandate of the HR-SR Committee is available on Énergir L.P.'s website at www.energir.com. For an overview of the HR-SR Committee, please refer to Item 10.2.1 *Governance Information*.

Green Mountain

Green Mountain has its own separate compensation committee, namely, the Compensation Governance Committee ("**CGC**"), which has no ties with Énergir's HR-SR Committee. The CGC follows Green Mountain's corporate governance policies to examine and recommend compensation as described herein. On the basis of their professional background, education and involvement on a board of directors, all members are sufficiently experienced to enable the CGC to make recommendations to the Green Mountain Board regarding the suitability of compensation policies and practices at Green Mountain.

b) Compensation Consultants

<u>Énergir, L.P.</u>

The HR-SR Committee may retain an independent consultant if necessary to assist it in discharging its duties and responsibilities.

Willis Towers Watson[28] has acted as a compensation consultant to the HR-CG Committee since 2006 and, in that capacity, was responsible for:

- providing analyses of market trends and practices with respect to the compensation of the President and Chief Executive Officer and the other executive officers of Énergir, L.P.;
- making recommendations to it concerning the composition of the comparison groups used by Énergir, L.P. to establish such compensation;
- conducting benchmark studies so that Énergir, L.P. can, if deemed necessary, harmonize its compensation policy with the comparison groups with respect to the President and Chief Executive Officer and the other executive officers;
- reviewing the form of Énergir, L.P.'s annual and long-term incentive programs and benchmark them against the practices of the comparison groups in this sector.

During fiscal year 2022, the HR-CG Committee conducted an executive officer compensation analysis process, for which it retained the services of Willis Towers Watson.

The following table shows the fees paid to Willis Towers Watson during fiscal years 2022 and 2021 in consideration of the services referred to above:

Type of fees (before tax)	2022	2021
Executive compensation/Related fees[1]	$74,601.76	$60,787.72
Other fees	$0.00	$0.00

(1) The amounts for fiscal year 2021 represent fees for services rendered in connection with the executive compensation analysis process and accompaniment in the review of the Long-Term Incentive Program. The amounts for fiscal year 2022 represent fees for services rendered in connection with the executive compensation analysis process.

Neither the Board nor the HR-SR Committee must pre-approve services that the consultants may provide at the request of Management.

<u>Green Mountain</u>

Since September 2012, Willis Towers Watson has acted as compensation consultant in connection with the competitive compensation assessment for the executive officers and the Green Mountain Board positions, so that Green Mountain may harmonize, if deemed necessary, its compensation programs with the comparison groups.

During fiscal year 2022, Green Mountain did not retain the services of an independent compensation consultant. Green Mountain retained the services of Willis Towers Watson to conduct a competitive compensation assessment for executive officer positions in the 2023 fiscal year and beyond.

c) Risk Management

<u>Énergir, L.P.</u>

Énergir, L.P. is committed to ensuring that its compensation program and policies are aligned with the long-term objectives of its partners. To accomplish this, Énergir, L.P. incorporates many general risk management principles into all decision-making processes across the organization and it regularly reviews, through third-party compensation consultants, its executive compensation program, which is adapted to Énergir, L.P.'s regulatory framework. This risk integration and review procedure helps ensure that its programs continue to support partner interests and regulatory compliance and are aligned with sound principles of risk management and governance.

(28) In 2006, Towers Perrin Canada Inc. provided compensation consulting services to the Énergir Inc. Human Resources Committee. The mandates of the Human Resources Committee and the Corporate Governance Committee have been combined since February 11, 2011. On January 1, 2010, Towers Perrin Canada Inc. and Watson Wyatt Inc. merged to form "Towers Watson Canada Inc." On January 4, 2016, Towers Watson and Willis Group Holdings merged to form "Willis Towers Watson." Since the Board committee mandates were consolidated on October 18, 2022, the compensation responsibilities of the HR-CG Committee have been assumed by the HR-SR Committee.

The HR-SR Committee oversees Énergir, L.P.'s compensation program from the perspective of whether they could encourage employees to take inappropriate or excessive risks that are reasonably likely to have a materially adverse effect on Énergir, L.P.

Énergir, L.P. uses the following compensation practices to mitigate risk:

- its pay for performance philosophy is embedded into its compensation program design;
- its total compensation is appropriately allocated to the various components of its compensation program and established based on the appropriate short- and long-term results;
- Énergir, L.P. believes its mix of pay programs, its approach to goal setting, the establishment of targets with multiple levels of performance and the evaluation of performance results assist it in mitigating excessive risk-taking that could harm its value and in ensuring that poor decisions by its executives are not rewarded;
- its compensation program includes a combination of short- and long-term elements that ensure its executive officers have the incentive to consider both the immediate and long-term implications of their decisions;
- its short-term incentive program does not focus unduly on one measure in particular, and includes a wide range of criteria so that executive officers are compensated for their short-term performance using a combination of financial, operational, health, safety, engagement, environment, GHG reduction, DEI and customer and employee metrics that are determined by Énergir, L.P. or the Régie;
- for the annual short-term incentive compensation program, performance thresholds are established that include both minimum and maximum payouts; and
- the long-term incentive program promotes long-term performance by offering a performance bonus that could increase substantially if a three-year target is exceeded, and performance thresholds are also established that include both minimum and maximum payouts.

The HR-SR Committee has discussed the concept of risk as it relates to Énergir, L.P.'s compensation programs and does not believe Énergir, L.P.'s program encourages excessive or inappropriate risk taking.

<u>Green Mountain</u>

Green Mountain is committed to ensuring that its compensation program and policies are aligned with the long-term objectives of its stakeholders – including its shareholder, customers and communities it serves. To accomplish this, Green Mountain incorporates many general risk management principles into all decision-making processes across the business and conducts reviews internally and through third-party consultants, as needed, of its executive compensation program. This risk integration and review procedure helps ensure that Green Mountain programs continue to support customer and stakeholder interests and regulatory compliance and are aligned with sound principles of risk management and governance.

The CGC oversees the compensation program from the perspective of ensuring pay is aligned with the goals and needs of Green Mountain's stakeholders, avoiding inappropriate or excessive risks and materially adverse effects on Green Mountain and its customers. Green Mountain uses the following compensation practices to mitigate risk:

- Green Mountain has a pay for performance philosophy that is embedded in its compensation design;
- Green Mountain applies structured compensation policies and practices to all executives;
- Green Mountain uses a mix of pay programs and goal setting, establishing targets with multiple levels of performance and evaluation of performance results, to drive good judgment and results;
- the Green Mountain compensation program includes a combination of short- and long-term elements that ensure its executive officers have the incentive to consider both the immediate and long-term implications of their decisions;
- executive officers are compensated for their short-term performance using a combination of customer, operational, safety and financial metrics that ensure a balanced perspective and many of the customer-driven metrics thresholds are established by the VPUC in its role as state regulator; and
- performance thresholds are established that include both minimum and maximum payouts, and executive incentive plans have financial and customer metric thresholds that would preclude payouts on incentives plans if Green Mountain experienced poor performance in those areas.

The CGC has considered the concept of risk as it relates to Green Mountain compensation programs and does not believe Green Mountain programs encourage excessive or inappropriate risk taking.

d) Hedging Policy

Énergir, L.P. and Green Mountain do not offer equity compensation because Énergir, L.P.'s Units and Green Mountain's shares are not traded on any exchange.

e) Discretionary Power

Under Énergir, L.P.'s *Compensation Policy for Senior Executives,* the Board on the recommendation of the HR-SR Committee may deem it appropriate to pay the executive officers amounts in excess of those provided for by the Policy in the event of exceptional results or extraordinary circumstances, with respect to any component of total compensation. The Board exercised its discretionary powers in regard to one Named Executive Officer during fiscal year 2022 by granting him a discretionary incentive greater than that provided for in the *Compensation Policy for Senior Executives*. For more information on this incentive, please refer to the *Summary Compensation Table* in Item 10.1.4 *Compensation Summary for Named Executive Officers* of this Annual Information Form.

The Green Mountain Board and the CGC may, at their discretion, modify incentive compensation in view of events or circumstances that would make it inappropriate to award incentive compensation strictly in accordance with Green Mountain's performance metrics. For fiscal year 2022, with respect to the long-term incentive compensation, the CGC exercised their discretionary power to raise the eligible executive officers to the 100% target.

10.1.3 Analysis of the Compensation of the Named Executive Officers

10.1.3.1 Compensation Policies for Named Executive Officers

Énergir, L.P.

The *Compensation Policy for Senior Executives*, from which the Named Executive Officers benefit, is designed:

- to attract, retain and motivate top-performing executives
- to also encourage them to enhance Énergir, L.P.'s strategic and organizational performance
- to provide total compensation that is close to the median for the comparison group if the objectives are achieved, with the possibility of higher amounts for results that exceed expectations.

The executive officers receive a compensation that is both fixed and variable and consists of five (5) components: (i) a base salary, (ii) pension plans, (iii) the allowances and employee benefits program, (iv) the annual short-term incentive compensation program, and (v) the long-term incentive program.

Green Mountain

The executive officer compensation policy of Green Mountain is designed:

- to attract, retain and motivate high calibre talent while balancing fiduciary responsibility to its shareholder and other stakeholders including the community in general

- to also promote the strategic objectives of Green Mountain, especially its service to customers

- to provide total compensation that is between the 25th and 50th percentile for the comparison group if objectives are achieved, with the possibility of higher amounts for results that exceed expectations.

Green Mountain's executive officers receive a compensation that is both fixed and variable and consists of five (5) components: i) base salary, ii) retirement benefits, in the form of a defined contribution retirement plan, iii) employee benefits program, iv) annual short-term incentive compensation, and v) long-term incentive compensation.

Services Agreement between Énergir L.P. and Green Mountain

Mr. Lepage has been acting as the Vice President, Chief Financial Officer and Treasurer of Green Mountain since August 5, 2019. Prior to his appointment at Green Mountain, he had been acting as Director of Finance and Treasurer of Énergir, L.P.

On April 30, 2021, Mr. Lepage was appointed as Chief Financial Officer of Énergir, L.P. Green Mountain continues to employ Mr. Lepage and entered into a services agreement with Énergir, L.P. Under this services agreement, Green Mountain, through Mr. Lepage, provides Énergir, L.P. with the services usually rendered by a chief financial officer. In consideration of these services, Énergir, L.P. pays to Green Mountain a monthly fee based upon a third-party review of the arms' length value of such services. For the services rendered to Énergir, L.P. in fiscal year 2022, Énergir, L.P. was billed a total of $549,246.82 by Green Mountain.[29]

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[29] The amount shown is in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022.

Mr. Lepage is subject to Green Mountain's compensation policy. More specifically, Green Mountain remains the sole and exclusive employer of Mr. Lepage and as such is responsible for the payment of his remuneration. The details of Mr. Lepage's compensation is presented in Item 10.1.4 *Compensation Summary for Named Executive Officers*.

10.1.3.2. Decision Regarding Compensation

<u>Énergir, L.P.</u>

The Board is responsible for determining the principles underlying the *Compensation Policy for Senior Executives*. The Board has set up an HR-SR Committee whose mandate, among other things, is to review all aspects of executive officer compensation and make recommendations in this regard.

The HR-SR Committee retains the services of an independent specialist from time to time to review the overall compensation of the President and CEO and other executive officers as regards Énergir, L.P.'s comparison groups and make appropriate recommendations regarding adjustments, if required. The diagram below illustrates the process used to set Énergir, L.P.'s executive officer compensation.

Decision Regarding Compensation

Overall Planning

1b. President and CEO
- establishment of the business's strategic initiatives
- establishment of the corporate objectives

1a. Independent Compensation Consultant
- analysis of the overall compensation of executive officers compared to Énergir, L.P. comparison groups
- making of appropriate recommendations regarding adjustments to the HR-SR Committee, if required

2. HR-SR Committee
- review of (i) the corporate objectives proposed by the President and CEO, and (ii) the strategic initiatives
- in determining these objectives, review of the results of previous years and setting of strategic initiatives at levels it considers sufficiently ambitious and demanding in light of past results and future issues
- recommendation of strategic initiatives and corporate objectives to the Board

3. Board (on recommendation of HR-SR Committee)
- establishment of the business's strategic initiatives
- approval of the corporate objectives

Annual Performance Assessment and Recommendations

4. President and CEO
- appraisal of the personal performance of each executive officer and reporting to the HR-SR Committee
- positioning of each executive officer within their respective salary scales, based on this appraisal and the total payroll allocated
- recommendation of the incentive compensation for each executive officer

5. HR-SR Committee
- appraisal of the performance of the President and CEO
- review of the report prepared by the President and CEO assessing the performance of the executive officers reporting to him
- evaluation of the extent to which the corporate objectives and strategic initiatives are met and making of recommendations to the Board
- review of the recommendations of the President and CEO with respect to the incentive compensation of executive officers
- review of the salary scales for each executive position

Annual Decision-making and Approvals

6. HR-SR Committee

- recommendation to the Board of the executive officers' incentive compensation
- recommendation to the Board of the executive officers' salary increase effective the following January 1st
- discretionary power to grant amounts to executive officers in excess of those provided for by the *Compensation Policy for Senior Executives* and recommendation to the Board in this regard

7. Board

- approval of the executive officers' incentive compensation
- approval of the executive officers' salary increase for the following January 1st
- approval of the use of the discretionary power to grant amounts in excess of those provided for in the *Compensation Policy for Senior Executives*

Green Mountain

The Green Mountain Board is responsible for determining the principles underlying Green Mountain's executive officer compensation philosophy. The Green Mountain Board has set up the CGC and mandated it, among other things, to review all aspects of executive compensation and make recommendations in this regard. The diagram below presents the process that is followed in setting Ms. McClure's and Mr. Lepage's compensation, along with that of the other executive officers of Green Mountain.

Decision Regarding Compensation

Overall Planning

1. Independent Compensation Consultant - periodically

- review of overall compensation of the President and CEO and the other executive officers
- comparison of compensation with that of the comparison group
- recommendation of necessary compensation policy adjustments

2a. CGC Committee - annually

- establishment of individual performance goals, as well as the relative weight assigned to each measure
- approval of the annual strategic and financial objectives of the President and CEO and the other executive officers

2b. Board - annually

- on the recommendation of the CGC, approval of the individual performance goals for the President and CEO

Annual Performance Assessment and Recommendations

3. President and CEO

- annual individual performance appraisal for each executive officer
- based on the annual appraisal and the total payroll allocated, positioning of each executive officer within their respective scales

4. CGC Committee

- review of the salary scales for each position
- assessment of the extent to which the annual strategic and financial objectives are met and recommendations in this regard
- review of the compensation proposed by the President and CEO for the executive officers

Annual Decision-making and Approvals

5. CGC Committee		6. Board
• recommendation to the Board with regard to the incentive compensation for executive officers • recommendation to the Board regarding the compensation for the President and CEO effective the following January 1st • recommendation to the Board with regard to the increase in the executive officers' salary effective the following January 1st • discretionary power to modify incentive compensation in view of events or circumstances that would make it inappropriate to award such compensation strictly in accordance with Green Mountain's performance metrics	➔	• approval of the incentive compensation for executive officers • approval of the compensation for the President and CEO • approval of the increase in the executive officers' salary on the following January 1st • approval of the use of the discretionary power for a bonus greater than that provided for in the *Executive Officer Compensation Policy*, if applicable in any year

10.1.3.3 Comparison Groups

The Board, on the recommendation of the HR-CG Committee, endorsed the Willis Towers Watson executive officers total compensation market study dated December 9, 2019 and the proposed comparison groups used by Énergir, L.P. for the President and CEO and the other executive officers.

With respect to Green Mountain, the compensation comparisons are periodically done[30] through proxy information from peer organizations as available as well as compensation surveys, both obtained through compensation consultants.

The table below sets out the comparison groups used in the compensation analysis for Énergir, L.P. and Green Mountain.

Comparison Groups Table for the Named Executives Officers

List of Companies for Énergir, L.P.		List of Companies for Green Mountain
Quebec Companies (19)	Companies in Other Canadian Provinces (12)	U.S. Companies (6)
Agropur Cooperative	Alberta Electric System Operator	Allete, Inc.
Boralex Inc.	ATCO Ltd.	Black Hills Power
BRP Inc.	Capital Power Corporation	Casella Waste Systems, Inc.
CAE Inc.	Emera Inc.	Montana - Dakota Utilities Company
Canam Group Inc.	Enbridge Gas Inc.	Madison Gas and Electric Co.
Cogeco Communications Inc.	ENMAX Corporation	Unitil Corp.
Cascades Inc.	EPCOR Utilities Inc.	
Dollarama Inc.	FortisAlberta Inc.	
Innergex Renewable Energy Inc.	Inter Pipeline Fund	
Lassonde Industries Inc.	Just Energy Group Inc.	
Quebecor Inc.	Toronto Hydro-Electric System Limited	
Resolute Forest Products Inc.	TransAlta Corporation	
Richelieu Hardware Ltd.		
Tembec Inc.		
Transat A.T. Inc.		
Transcontinental Inc.		
TFI International Inc.		
Velan Inc.		
Uni-Select Inc.		

The Canadian companies are in the energy and transformation and distribution services sectors. The Quebec companies are in various sectors such as distribution, services and manufacturing. As for the U.S. companies, they are similar-sized utility companies or Vermont-based general companies of similar size to Green Mountain.

[30] The last compensation comparison was completed in 2018; another is anticipated in fiscal year 2023.

Énergir Inc.'s HR-SR Committee and Green Mountain's CGC are respectively of the opinion that the comparison groups chosen for these two companies are relevant for the purposes of establishing points of comparison for the compensation of the executives officers, as the groups are composed of companies operating in similar fields as Énergir, L.P. and Green Mountain or have properties comparable to those of Énergir, L.P or Green Mountain. The HR-SR Committee of Énergir Inc. and the CGC of Green Mountain are therefore of the opinion that the issues relating to the compensation of the Named Executive Officers are likely to be similar to those related to the compensation of the executives of the companies that form the comparison groups.

10.1.3.4 Components of the Named Executive Officer Compensation Programs

Énergir, L.P.

As stated under Item 10.1.3.1 *Compensation Policies for Named Executive Officers*, the executive compensation consists of fixed and variable components. The following table presents these components and shows the position of each compensation component in relation to the comparison group described under Item 10.1.3.3 *Comparison Groups*.

Components of Compensation of Énergir Inc.				
Type of Compensation	**Components**	**Position with respect to comparison group**	**Objectives**	**Description**
Fixed	Base salary	Comparison group median	• retention • recognition of skills, competence and experience	– Base salary for executive officers, including Named Executive Officers, is determined according to a salary scale for each position. – The base salary scale for Named Executive Officers is determined taking into consideration Énergir, L.P.'s comparison groups for positions involving similar responsibilities. – Salary increases for employees whose base salary falls within their scale are based on their annual appraisal for their personal performance.
	Pension and allowances	Comparison group median (but may be raised above comparison group median to retain executive officers)	• provision of adequate retirement income • commensurate with position	– Readers are referred to Item 10.1.3.9 *Retirement Benefits* of this Annual Information Form, which presents the retirement plans.
	Employee benefits program	Above median of comparison group. This program is designed to be competitive with equivalent positions in comparable companies.	• commensurate with position • capped since January 1, 2009	– The group insurance plan covers: • death • disability • illness – The allowance program allows executive officers to receive, in cash or in the form of an allowance for automobile and other expenses that are deemed eligible, up to: • annual base salary X 12.5% • with a maximum based on position held: ◦ Executive Vice President, Quebec and vice presidents: $25,000[1] ◦ President and CEO: $40,000. – The costs of the group insurance plan are primarily borne by the employer.

[1]The Executive Vice President, Quebec receives an additional allocation of $2,000 to lease an electric vehicle.

<table>
<tr><th colspan="5">Components of Compensation of
Énergir Inc.</th></tr>
<tr><th>Type of Compensation</th><th>Components</th><th>Position with respect to comparison</th><th>Objectives</th><th>Description</th></tr>
<tr><td rowspan="2">Variable</td><td>Annual Incentive Compensation</td><td>Comparison group median</td><td>• recognition of individual performance and overall performance of Énergir, L.P.</td><td>– Named Executive Officers may receive a performance bonus based on their performance in achieving corporate objectives relating to Énergir, L.P.'s overall performance according to the applicable regulatory framework.

– Based on performance, the Annual Incentive Compensation as a percentage of salary may be up to:
• 60.0% of base salary for the President and CEO;
• 50.0% of base salary for Executive Vice President, Quebec;
• 40.0% of base salary for the other executive officers.

– In the event of exceptional results or extraordinary circumstances, the Board on the recommendation of the HR-SR Committee may decide on the appropriateness of paying amounts in excess of those provided for under the Compensation Policy for Senior Executives with respect to any component of total compensation</td></tr>
<tr><td>Long-Term Incentive Program</td><td>Comparison group median</td><td>• creation of long-term economic and strategic value for Énergir, L.P.</td><td>– Please refer to Item 10.1.3.7 Long-Term Incentive Program of this Annual Information Form, which presents the long-term incentive program</td></tr>
</table>

<u>Green Mountain</u>

As Named Executive Officers, Ms. McClure and Mr. Lepage[(31)] receive both fixed and variable compensation, consisting of five (5) components: i) base salary, ii) defined contribution retirement plan, iii) employee benefits program, iv) annual short-term incentive compensation, and v) long-term incentive compensation. The following table presents these components and shows the position of each component in relation to the comparison group described under Item 10.1.3.3 *Comparison Groups*.

<table>
<tr><th colspan="5">Components of Compensation
Green Mountain</th></tr>
<tr><th>Type of Compensation</th><th>Components</th><th>Position with respect to comparison group</th><th>Objectives</th><th>Description</th></tr>
<tr><td rowspan="3">Fixed</td><td>Base salary</td><td>Below median of comparison group</td><td>• retention
• recognition of skills, competence and experience</td><td>– Base salary for the President and CEO and other executive officers is determined according to a salary scale for the position.
– The base salary scale for the President and CEO and other executive officers is positioned between the 25th and 50th percentile of the comparison group, and is determined taking into account Green Mountain’s comparison groups for positions of similar responsibility.
– Salary increases for employees whose base salary falls within their scale are based on their annual appraisal for their personal performance.</td></tr>
<tr><td>Retirement Benefits</td><td>Comparison group median</td><td>• provision of adequate retirement income
• commensurate with position</td><td>– Readers are referred to the Item 10.1.3.9 Retirement Benefits of this Annual Information Form, which presents the retirement benefits.</td></tr>
<tr><td>Employee Benefits Program</td><td>Comparison group median</td><td>• commensurate with position
• retention</td><td>Deferred Compensation
– Available to executive officers only
– Deferral and then interest accrual of compensation is available both for Green Mountain aggregate (base and variable) salary and for VELCO board compensation.
Life Insurance Plan
– The insurance policy provides adequate protection in the event of death, disability or illness.
– The coverage is equivalent to four times base salary for the President and CEO and three times the base salary for the other executive officers.
Payment Features
– The costs of the plan are primarily borne by the employer.
– Employee and indirect benefits for executive officers are designed to be competitive with equivalent positions in comparable companies.
– They are periodically reviewed by the CGC.</td></tr>
</table>

(31) For more details on Mr. Lepage's compensation, please see Item 10.1.3.1 *Compensation Policies for Named Executive Officers.*

Components of Compensation Green Mountain				
Type of Compensation	**Components**	**Position with respect to comparison group**	**Objectives**	**Description**
Variable	Short-Term Incentive Compensation	Below median of comparison group	• recognition of individual performance and overall performance of Green Mountain	– The President and CEO may receive a performance bonus based on her performance in achieving : • corporate service quality objectives, i.e., 16 customer service quality performance standards (60.0% of award); • personal objectives set for each year (40.0% of award). She must achieve 90.0% of the allowed rate of return on equity to be eligible for an award. – Based on performance, the annual incentive compensation of the President and CEO, as a percentage of salary, may be up to 60.0% of base salary, with target set at 50.0% of base salary, respectively. – The Chief Financial Officer may receive a performance bonus based on his performance in achieving: • corporate service quality objectives, i.e., 16 customer service quality performance standards (60.0% of award); • personal objectives set for each year (40.0% of award). He must achieve 90.0% of the allowed rate of return on equity to be eligible for an award. – Based on performance, the annual incentive compensation of the Chief Financial Officer, as a percentage of salary, may be up to 36.0% of base salary, with the target set at 30.0% of base salary, respectively.

Variable	Long-Term Incentive Compensation	Below median of comparison group	• creation of long-term economic value for Green Mountain and its customers	– The goal of the Long-Term Incentive Program is to promote the creation of long-term economic value for Green Mountain – For the three-year cycles ending on September 30, 2021 and 2022,[1] the creation of economic value is based on four measurements: • Return on Equity • Sustainable Bill Impacts • Building Financial Strength and Stability • Synergy savings from Merger integration – Changes to these values are determined over a three-year period and are the basis for annual bonus payments to executive officers after each three-year cycle. – A new three-year cycle begins on October 1 of each year and new performance goals are set within 120 days of the start of each cycle. **Target bonus** – The performance target award for the CEO is 85.0% of base salary and is based on the achievement of each performance level, namely the threshold (60.0%), the target (100.0%) or the ideal (120.0%). – The performance target award for the Chief Financial Officer is 40.0% of base salary and is based on achievement of each performance level, namely the threshold (60.0%), the target (100.00%) or the ideal (120.0%).

(1) For the three-year cycle ending on September 30, 2023, the creation of economic value is based on three measurements: Return on Equity, Building Financial Strength and Stability, and Climate and Carbon Achievement.

10.1.3.6 Objectives

Énergir, L.P.

The table below shows the Named Executive Officers' objectives as well as the achievement of the objectives in fiscal year 2022.

Corporate Objectives (Corporate objectives result calculations are validated by the internal auditors.)	
Partners' Net Income[1]	**2022 Objectives Achieved**
– This includes : • the result for Quebec distribution activities ("**QDA**"); • the result of the other activity sectors. – This annual budget is approved at the beginning of the fiscal year by the Board, on the recommendation of the HR-SR Committee.	– The result for income from QDA activities was $153.3 million compared to a target of $137.6 million and the result for non-QDA activities was $103.8 million compared to a target of $88.4 million, for a total of $257.1 million compared to the target of $226.0 million. – The result triggered payment of a proportionate share of the applicable annual incentive compensation.
QDA Operations	**2022 Objectives Achieved**
– This is measured by two categories of indicators: corporate indicators and indicators imposed by the Régie: • The corporate indicators are: Customer satisfaction, Customer attrition rate, New sales, Energy efficiency and their Retention, Mobilization, Number of surveys and Attainment of occupational health and safety objectives; • The indicators required by the Régie are: Customer satisfaction, Compliance with meter reading policy, Emergency response time, Preventive maintenance programs, Compliance with collection and service interruption procedure, Obtaining and maintaining the ISO 14001 certification, GHG emission reduction, and Overall satisfaction with Énergir, L.P. large enterprises market. – The overall result for the "Distribution of Natural Gas in Quebec" performance indicators takes into consideration weighting between corporate indicators and indicators	– The result is 82.6%. – The result triggered payment of a proportionate share of the applicable annual incentive compensation.
Strategic Initiatives	**2022 Objectives Achieved**
– At the end of each fiscal year, the HR-SR Committee evaluates the extent to which the various activities for this objective have been achieved during the fiscal year, and awards a rating based on those accomplishments. – The evaluation takes into account the importance of each project, the expected return in relation to Énergir, L.P.'s strategic objectives, and their completion status.	– The result recognized by the Board for this indicator is 95.0% for the QDA and 85.0% for the group. – The result triggered payment of a proportionate share of the applicable annual incentive compensation.
Occupational Health and Safety Objectives ("OHS")	**2022 Objectives Achieved**
OHS objectives have been included for each Named Executive Officer to influence their conduct and commitments. The objective has five indicators, which are: • the frequency of accidents; • the severity of those accidents; • the implementation of the three-year Occupational Health and Safety Plan; • the total number of close-call incidents reported by employees; and • participation in the "Leadership in action" program, which consists of activities and discussions on the promotion, by executive officers, of workplace safety and mental health.	– The achievement result is 71.0%. – The result triggered payment of a proportionate share of the applicable Annual Incentive Compensation.

[1] This area is based on the net income attributable to partners, as calculated in Énergir, L.P.'s 2022 Financial Statements, adjusted to exclude the effects of exchange rate fluctuations, certain expenses, unforeseen revenues in the budget and the impact of the disposal of a subsidiary's assets.

Green Mountain

The table below presents the objectives of Ms. McClure and Mr. Lepage, in his capacity as Vice President, Chief Financial Officer and Treasurer, of Green Mountain, as well as the achievement of the objectives in fiscal year 2022.

Corporate Service Quality Objectives	Objectives Achieved in 2022
– Green Mountain's service quality plan performance standards include measurements relative to customer satisfaction, system reliability, and responsiveness to customer requests, workplace safety, operational efficiency and billing accuracy. The target performance is determined at the beginning of the year. The determination as to final payments is undertaken only after the audited financials are complete and service quality performance for the calendar year has been formally submitted to the VPUC. – The short-term incentive plan has the unique feature of different performance periods for different features of the incentive plan. The individual portion of the award can be earned and calculated for the fiscal year. However, the corporate service quality goals are determined by calendar year performance, with the first quarter of the fiscal year determining the final results, when Green Mountain's annual results are then audited, filed with the VPUC and approved by the CGC. – The earnings calculation for fiscal year 2022 includes corporate service quality performance results from calendar 2021, which earnings were earned, approved and paid within fiscal year 2022, along with a personal objectives component.	– For Fiscal 2022, the results of Ms. McClure and Mr. Lepage for the corporate goal component were based on calendar year 2021 and were earned and determined in February 2022, after the close of the 2021 calendar year performance period, and the portion of the award was paid to them in February 2022. – For fiscal year 2022, Ms. McClure's results related to corporate goals attained 120.0% of target and represent 60.0% of the short-term incentive award. – For fiscal year 2022, Mr. Lepage's results related to corporate goals attained 120.0% of target and represent 60.0% of the short-term incentive award.
Individual Performance Goals	**Objectives Achieved in 2022**
– The individual performance goals, as well as the relative weight assigned to each measure, is established in writing for each participant no later than 90 days after the beginning of each fiscal year by the CGC after consultation with the CEO and is approved by the Green Mountain Board.	– For fiscal year 2022, the individual goal component of the short-term incentive compensation program was earned over fiscal year 2022 and will be paid in the coming fiscal year in February 2023.
Individual Goals for Ms. McClure and Mr. Lepage	**Objectives Achieved in 2022**
– Mari McClure: her individual performance goals were notably related to effective regulatory proceedings, strong financial results, development of innovative customer programs, community and stakeholder relations, and improvement in customer service including expanded communication options. – Mathieu Lepage: his individual performance goals were notably related to strong financial performance, effective regulatory proceedings, as well as development of innovative customer programs, community and stakeholder relations and strong customer service.	– For fiscal year 2022, Ms. McClure earned 104% of target for the individual component of the short-term compensation program, which accounts for 40% of the total award. – For fiscal year 2022, Mr. Lepage earned 97% of target for the individual component of the short-term compensation program, which accounts for 40% of the total award.

10.1.3.7 Long-Term Incentive Program

Énergir, L.P.

The former long-term incentive program of Énergir, L.P., which had been in effect since October 1, 1997 (the "**Former Program**"), was replaced by a new long-term incentive program that came into effect on October 1, 2020 (the "**New Program**"). The first payment will be made to the Named Executive Officers at the end of fiscal year 2023, namely on September 30, 2023.

Former long-term incentive program

The Former Program was based on the two following measures: (i) the spread between the return on partners' equity and the average return authorized by the regulatory bodies governing natural gas in Quebec (Régie) and electricity in Vermont (VPUC), and (ii) the growth in partners' value. Changes in economic value were determined using a three-year moving average and served as the basis for annual bonus payments to executive officers after each three-year cycle.

A new three-year cycle began on October 1 of each year. One of the main features of the program was the fact that the bonus reserve (hereinafter the "**reserve-at-risk**") was put at risk each year so as to promote stable performance. The reserve-at-risk (i.e., two-thirds (2/3) of the total reserve) was the balance of what could not be paid at the end of a fiscal year and was carried over to the following fiscal year. For the annual bonus calculation, the payment factor was based on a formula including the previous fiscal year's reserve and the results at the end of a fiscal year. The payment of that annual bonus represented one-third (1/3) of the total reserve. As a result, the annual payment factor increased or decreased depending on each fiscal year's results.

As part of the transition from the Former Program to the New Program, the reserve-at-risk will be calculated, based on the results for September 30, 2020, in two parts so as to bring the balance to zero and will be paid in two instalments, one in December 2021 and another in December 2022.

New long-term incentive program

The New Program is designed to retain and strengthen the commitment of named executives, including the Named Executive Officers,[32] all the while ensuring that they are focused on the financial and strategic performance of the business. The New Program is based on the two following performance measures:

Indicator	Measure	Value (Weighting)	Definition/ Composition
Financial	Free cash flow ("**FCF**")	75%	The FCF corresponds to cash flows related to operating activities adjusted to exclude the variation of the effects of regulatory and operating assets and liabilities. It also includes the depreciation deduction for regulated activities, maintenance capital for unregulated activities and distributions to non-controlling partners.
Strategic	Decarbonization effort: Reduction of GHG emissions	25%	In Quebec, three complementary segments are monitored for a value of **75% of the indicator:** 1. Energy efficiency; 2. Injection RNG; 3. Transfer of customers to dual energy (calculated as tonnes of CO_2 equivalent). For Green Mountain, the achievement of GHG reduction objectives in Vermont is calculated on the achievement of three tiers, for a value of **25% of the indicator:** Tier 1: Total electricity sales from all sources of renewable energy; Tier 2: Total electricity sales from new generation of renewable energy; Tier 3: In addition to attainment of Tier 2, fossil fuel savings resulting from energy transformation projects are added (calculated as megawatt-hours).

The payment factor is calculated based on a recommended grid:

Recommended Grid	Payment factor
Threshold[1]	0.5
Target	1
Ideal	2

(1) If the result is less than the threshold, a factor of 0 is assigned.

(32) With the exception of Ms. McClure and Mr. Lepage, who are compensated by Green Mountain. For more information on Mr. Lepage's compensation, please refer to Item 10.1.3.1 *Compensation Policies for Named Executive Officers*.

To be eligible for the bonus, the Named Executive Officer[33] must have been in Énergir, L.P.'s employ on the last day of the fiscal year in question. In the event of departure before that date, the annual payment is lost, except in the following situations:

- Retirement, death or disability;
- Departure following dismissal within 18 months of a change in control of Énergir Inc., "i.e., the direct or indirect acquisition, by a third party, of voting shares in Énergir Inc. representing at least 51% of all voting shares in Énergir Inc., as well as any transaction enabling a third party to exercise "de facto" control of the Énergir Inc.

In such a situation, the payment for the current year is prorated according to the time elapsed. The amounts are determined based on the results at the end of the current fiscal year. The annual payment due is made in the months after the end of the fiscal year based on the audited financial statements and upon the approval of the Board.

Targets are set for a cumulative period of three years that begins on October 1st of each fiscal year. One payment is made to the named executives at the end of each cumulative period: the President, the Executive Vice President and the vice presidents.

The bonus payable is calculated as follows:

FCF	SALARY	X	TARGET BONUS	X	PAYMENT FACTOR	=	TOTAL BONUS	X	75%	=	BONUS PAYABLE
GHG	SALARY	X	TARGET BONUS	X	PAYMENT FACTOR	=	TOTAL BONUS	X	25%		

The target bonus, as a percentage of annual salary, is:

- President 100%
- Executive Vice President 60%
- Vice presidents 45%

<u>Green Mountain</u>

Green Mountain's long-term incentive program is further described in Item 10.1.3.4 *Components of the Named Executive Officer Compensation Programs* under the Green Mountain section. The bonus payable is calculated as follows:

BASE SALARY	X	TARGET PERCENTAGE	X	WEIGHTED PERFORMANCE FACTOR	=	BONUS PAYABLE

The target bonus, as a percentage of annual salary, is:

- Chief Executive Officer 85%
- Chief Financial Officer 40%
- Vice presidents 40%

[33] *Idem.*

The following table shows the long-term incentive bonus that will be paid to Ms. McClure and Mr. Lepage based on the results for the three-year cycle ended September 30, 2022 :

Long-Term Incentive Program Bonus Table

Name	2022 Long-Term Bonus ($)	Reserve at risk ($)
Mari McClure[(1)] President and CEO	510,345	N/A
Mathieu Lepage[(1)] Vice-President, Chief Financial Officer and Treasurer	167,732	N/A

(1) Ms. McClure and Mr. Lepage are paid in U.S. dollars. The amount shown is in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022. The amount reflects the discretionary decision of the CGC to raise eligible executive officers to the 100% target for the 2022 fiscal year, as described in Item 10.1.2 *Report on Named Executive Officer Compensation*.

10.1.3.8 Incentive Plan Awards

The following table shows the value vested or value earned by the Named Executive Officers under Énergir, L.P. and Green Mountain's incentive plans during fiscal year 2022. These amounts will be paid during fiscal year 2023.

Incentive Plan Awards Table
Value Vested or Earned During the Fiscal Year

Name	Option-based awards – value vested or earned during the year ($)	Share-based awards – value vested or earned during the year ($)	Non-equity incentive plan compensation – value earned during the year ($)		Total ($)
			Annual Incentive Plan	Long-Term Incentive Plan	
Éric Lachance President and Chief Executive Officer	N/A	N/A	302,403	981,101	1,283,504
Mathieu Lepage[(1)] Chief Financial Officer of Énergir, L.P. and Vice President, Chief Financial Officer and Treasurer of Green Mountain	N/A	N/A	194,402[(2)]	167,732[(3)]	362,134
Stéphanie Trudeau Executive Vice President, Quebec	N/A	N/A	180,105	430,500	610,605
Renault-François Lortie Vice President, Customers and Gas Supply	N/A	N/A	144,807[(4)]	252,788	397,595
Mari McClure[(1)] President and CEO, Green Mountain	N/A	N/A	330,738[(5)]	510,345[(6)]	841,083

(1) Mr. Lepage and Ms. McClure are paid in U.S. dollars. The amounts shown are in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022.
(2) Annual Short-Term Incentive Plan is earned during both fiscal year and calendar year. The fiscal 2022 amount represents the amount of $90,576 earned through December 2021, the first quarter of the fiscal year and paid in February 2022, plus the individual goal results of $103,826 earned in the 2022 fiscal year and payable in the fiscal year ending on September 30, 2023.
(3) This amount will be paid during the fiscal year ending on September 30, 2023.
(4) This amount includes a $32,000 discretionary bonus greater than the one provided for in the *Compensation Policy for Senior Executives.*
(5) The Annual Short-Term Incentive Plan is earned during both fiscal year and calendar year. The fiscal 2022 amount represents the amount of $205,853 earned through December 2021, the first quarter of the fiscal year and paid in February 2022, plus the individual goal results of $124,885 earned in the 2022 fiscal year and payable in the fiscal year ending on September 30, 2023.
(6) This amount will be paid during the fiscal year ending on September 30, 2023.

10.1.3.9 Retirement Benefits

This section is presented in two parts, one covering the retirement benefits which are offered to the executive officers of Énergir, L.P. and another covering the retirement benefits offered to Ms. McClure, President and CEO of Green Mountain and Mr. Lepage, Chief Financial Officer of Énergir, L.P. and Vice President, Chief Financial Officer and Treasurer of Green Mountain.

Énergir, L.P.

Registered Pension Plan and Post-Retirement Allowance Program (“Program”)	
Eligibility	– Executive officers of Énergir, L.P.
Description of plans	– The registered pension plan is a defined benefit plan and is non-contributory for executive officers. This plan is subject to the laws governing pension plans under provincial jurisdiction (Quebec) and the tax limits prescribed by the Canada Revenue Agency – The Program is intended to offset the impact of the limits imposed by tax legislation on the retirement pension provided by the registered pension plan and is non-contributory
Reasons for payment	– Encourage long-term retention of executive officers by rewarding them for their continued service at Énergir, L.P.
Normal age of retirement (without annuity reduction)	– 65
Credited years of services	– Save for some exceptions, accumulation of one year of service for each year of participation
Life annuity formula	– 1.35% of the average of the five highest consecutive annual base salaries preceding retirement up to the average maximum annual eligible earnings (“**MAEE**”) for the same period, plus 2.0% of the average of the salaries in excess of the average MAEE, multiplied by the number of years of service giving entitlement to a pension under this formula
Reduction of the life annuity	– For the annuity relating to years of service prior to January 1, 2016, reduction of 0.25 of 1.0% (maximum 15.0%) for each month between the date of early retirement and the earlier of the participant’s 60th birthday or the date on which the sum of his (her) age and years of service equals 85 – For the annuity relating to years of service as of January 1, 2016, reduction of 5/12 of 1.0% (maximum 25.0%) for each month between the date of early retirement and the earlier of the participant’s 60th birthday or the date on which the sum of his (her) age and years of service equals 90, but not prior to the participant’s fifty-eighth birthday
Temporary annuity	– Payable to participants who retire before 65 years of age and equal to the product of 0.65% of the average MAEEs multiplied by the years of service prior to January 1, 2010, $125 multiplied by the years of service from January 1, 2010 to December 31, 2015 and 0.50% of the average MAEEs multiplied by the years of service as of January 1, 2016
Discretionary facet	– Executive officers, including the Named Executive Officers, may elect to make voluntary contributions to a discretionary facet of the Pension Plan in order to acquire certain additional benefits.
Security for Program commitments	– Secured by letters of credit deposited in retirement compensation trusts

Green Mountain

Defined Contribution Retirement Plan	FIXED
Eligibility	– Executive officers and all employees of Green Mountain.
Plan definition	– The defined contribution plan is subject to regulations governing 401(k) plans under federal jurisdiction. – The plan includes contributory provisions for employees and the employer.
Contribution provisions	– Employees who choose to participate may contribute any percentage of their salary on a pre-tax basis, up to an annual maximum set by the Internal Revenue Service, which was $26,049[1] in 2022, or $ 34,309[1] for those over age 50. – Green Mountain contributes 3.75% of the base salaries of employees who do not qualify for the defined benefit pension plan and matches 100.0% of employee contributions up to 4.0% of their base salary.
Payment provisions	– Employees are eligible for distribution benefits at age 59 ½, and are required to start taking distributions by age 70.

(1) The amounts shown are converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $ 1.2707 per U.S. dollar in 2022.

The following table shows Ms. McClure and Mr. Lepage's accumulated value in the 401(k) retirement plan as of September 30, 2022.

401(k) Retirement Plan Table

Name	Accumulated value at start of year ($)	Compensatory ($)	Non-compensatory ($)	Accumulated value at year end ($)
Mari McClure[1] President and CEO	$640,474	29,067[2]	(123,901)	545,640
Mathieu Lepage[3] Chief Financial Officer of Énergir, L.P. and Vice President, Chief Financial Officer and Treasurer of Green Mountain	—	51,358[4]	23,321	74,679

(1) Ms. McClure is paid in U.S. dollars. The amounts shown are in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022.
(2) Green Mountain contributions totaled $29,067 and investment performance was -5.8% on a total of employee and employer contributions of $52,606.
(3) Mr. Lepage is paid in U.S. dollars. The amounts shown are in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022.
(4) Green Mountain contributions totaled $51,538 and investment performance was -10.8% on a total of employee and employer contributions of $92,506.

Non-Qualified Deferred Compensation Plan	FIXED
Features	The executive officers are eligible to participate in a deferred compensation plan for Green Mountain executives. Ms. McClure is also eligible to participate in a deferred compensation plan for Board Members of VELCO which is partially owned by Green Mountain (38.8% ownership), as Ms. McClure currently maintains a seat as part of her duties as President and CEO of Green Mountain. Ms. McClure chose not to participate in either of these plans for fiscal year 2022. Mr. Lepage also did not choose to participate in the deferred compensation plan for Green Mountain executives. – Green Mountain Plan: May defer a portion of base salary up to $95,303[(1)] (US$75,000) per calendar year – VELCO Board Plan: May defer up to 100.0% of compensation received – For both plans, amounts deferred are credited to a separate account for each participant.
Monthly Growth Percentage	Each of the following plans credits the participant's deferral account with a monthly growth percentage. – Green Mountain: One twelfth of the average annual yield on public utility bonds as determined by Moody's Investors Service and published in the issue of "Moody's Public Utility" on the date closest to the fifteenth day of said month, or such other growth percentage as the Green Mountain Board may from time to time determine to be substantially equivalent to the average annual yield on public utility bonds as determined by Moody's Investors Service. The rating level to be used for computing the growth percentage for each deferral is Green Mountain's rating at the time the deferral election is executed. – VELCO: The growth percentage for VELCO deferred compensation is calculated each month by an amount equal to the product of the balance recorded in the account as of the first day of said month multiplied by one-twelfth of the amount established by Moody's Investors Service as the Baa Long-Term Corporate Bond Yield for the first day of that month.

(1) The amount shown is in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was $1.2707 per U.S. dollar in 2022.

Énergir, L.P. and Green Mountain

Defined Benefit Registered Pension Plan & Post-Retirement Allowance Program Table

Name	Credited years of service[1]		Annual life benefits payable ($)		Accrued benefit obligations at beginning of fiscal year ($)[2]	Variations attributable to compensation items ($)	Variations attributable to non-compensation items ($)[3]	Accrued benefits obligations at end of fiscal year ($)[4] (g)
	Registered Pension Plan	Post-Retirement Allowance Program	At end of fiscal year	At age 65				
(a)	(b)	(b)	(c)1)	(c)	(d)	(e)	(f)	(d + e + f = g)
Éric Lachance President and Chief Executive Officer	5.65	5.65	50,100	235,000	824,600	176,300	(295,100)	705,800
Mathieu Lepage Chief Financial Officer of Énergir, L.P.[5] and Vice President, Chief Financial Officer and Treasurer of Green Mountain	10.99	—	37,600	37,600	512,300	—	(152,100)	360,200
Stéphanie Trudeau Executive Vice President, Quebec	15.74	10.00	86,500	262,000	1,209,200	189,500	(359,400)	1,039,300
Renault-François Lortie Vice President, Customers and Gas Supply	8.25	5.75	37,700	156,500	569,900	114,900	(218,900)	465,900
Mari McClure President and Chief Executive Officer of Green Mountain[6]	—	—	—	—	—	—	—	—

(1) As of September 30, 2022.

(2) As at September 30, 2021, i.e., at the measurement date of the pension obligations used in preparing Énergir, L.P.'s audited consolidated financial statements for fiscal year 2021. These amounts were calculated based on the same assumptions and methods as shown in the note to the consolidated financial statements dealing with Employee Future Benefits at that date.

(3) The variations attributable to non-compensation items are basically the net effect of the interest on the accrued benefit obligations and the changes in methods and assumptions.

(4) As at September 30, 2022, i.e., at the measurement date of the pension obligations used in preparing Énergir, L.P.'s 2022 Financial Statements. These amounts were calculated based on the same assumptions and methods as shown in the note to the consolidated financial statements dealing with Employee Future Benefits at that date.

(5) Mr. Lepage has held the position of Chief Financial Officer of Énergir, L.P. since April 30, 2021. He accumulated years of service for the purposes of Énergir, L.P.'s registered pension plan up to April 30, 2021. Mr. Lepage is not eligible to participate in the Defined Benefit Registered Pension Plan or the Post Retirement Allowance Program now or in the years ahead, but he is eligible for Green Mountain's 401(k) Retirement Plan and Non-Qualified Deferred Compensation Plan, which are discussed in this section.

(6) Ms. McClure is not eligible to participate in these plans, either now or in the years ahead. Ms. McClure is eligible for Green Mountain's 401(k) Retirement Plan and Non-Qualified Deferred Compensation Plan, which are discussed in this section.

10.1.4 Compensation Summary for Named Executive Officers

The following table shows the information regarding compensation for the Named Executive Officers for the last three fiscal years:

Summary Compensation Table

Name & Principal Position (a)	Fiscal Year (b)	Salary ($) (c)	Non-Equity Incentive Plan Compensation ($) (d)		Value of Pension Plans ($) (e)	Other Compensation [1] ($) (f)	Total Compensation (g) ($) (c + d + e + f = g)
			Annual Incentive Plan	Long-Term Incentive Plan			
Éric Lachance President and Chief Executive Officer	2022	556,544	302,403	309,441[2]	176,300	671,660[3]	2,016,348
	2021	540,974[4]	295,637	309,440	195,100	234,860[3]	1,576,011
	2020	493,671	270,969	255,677	319,000	—	1,339,317
Mathieu Lepage[5] Chief Financial Officer of Énergir, L.P. and Vice President, Chief Financial Officer and Treasurer of Green Mountain	2022	419,331	194,402	167,732	51,358[6]	194,731[7]	1,027,554
	2021[8]	392,689	131,593	167,706	31,200[9]	81,158[10]	804,346
	2020[11]	388,850	70,178	63,097	49,000	2,520	573,645
Stéphanie Trudeau Executive Vice President, Quebec	2022	400,648	180,105	137,175[2]	189,500	293,325[3]	1,200,753
	2021	370,324[12]	171,540	137,175	122,500	86,835[3]	888,374
	2020	355,499	160,631	114,139	171,300	—	801,569
Renault-François Lortie Vice President, Customers and Gas Supply	2022	315,754	144,807[13]	72,767[2]	114,900	180,021[3]	828,249
	2021	294,120	110,120	72,767	127,900	62,233[3]	667,140
	2020	270,430	128,275[14]	60,277	110,000	—	568,982
Mari McClure[5] President and Chief Executive Officer, Green Mountain	2022	624,549[15]	330,738	510,345	29,067[16]	6,322[17]	1,501,021
	2021	599,726[18]	317,879	485,966	27,633[19]	6,321[20]	1,437,526
	2020	581,761[21]	190,932	272,179	35,348[22]	2,892[23]	1,082,572

(1) For an explanation of this other compensation, please refer to the explanatory table for the Allowances and Employee Benefits Program under Item 10.1.3.4 *Components of the Named Executive Officer Compensation Program*.
(2) This amount represents the last payment made under the former long-term incentive program, as indicated in Item 10.1.3.7 *Long-Term Incentive Program.*
(3) This amount represents a lump sum compensating monetarily for the market discrepancy for the transition period between the former long-term incentive program and the new long-term incentive program.
(4) The 2021 Annual Information Form indicated Mr. Lachance's salary for the January 1, 2021 to September 30, 2021 period. That amount was corrected in this Annual Information Form to reflect the salary for the October 1, 2020 to September 30, 2021 period.
(5) Mr. Lepage and Ms. McClure are paid in U.S. dollars. The amounts shown are in Canadian dollars converted on the basis of the average exchange rate used to present expense information in the 2022 Financial Statements, which was 1.2707 per U.S. dollar in 2022. As for the compensation paid to Ms. McClure and Mr. Lepage for the fiscal year ended September 30, 2021 and for the fiscal year ended September 30, 2020, the average exchange rate used was $1.2705 per U.S. dollar in 2021 and $1.3389 per U.S. dollar in 2020.
(6) This amount represents a variation in the compensatory amount of Mr. Lepage's 401(k) retirement plan, as he is now participating therein for Green Mountain as described in Section 10.1.3.9, and includes a lump-sum catch-up contribution at the time he joined the plan in the first quarter of fiscal year 2022.
(7) This amount includes an annual lump payment of $192,014 for fiscal year 2022 payable to Mr. Lepage for performing additional duties for Énergir, L.P. It is paid by Green Mountain and reimbursed by Énergir, L.P. through the monthly fee described in Item 10.1.3.1 *Compensation Policies for Named Executive Officers* above. This amount also includes $2,717 of life insurance premiums, which were not deferred.
(8) Mr. Lepage has been acting as the Vice President, Chief Financial Officer and Treasurer of Green Mountain since August 5, 2019. On April 30, 2021, Mr. Lepage was appointed Chief Financial Officer of Énergir, L.P. A services agreement was entered into between Énergir, L.P. and Green Mountain, as described in Item 10.1.3.1 *Compensation Policies for Named Executive Officers*.
(9) This amount represents a variation in the compensatory elements.
(10) This amount includes an annual lump payment of $78,612 for the period between May and September 2021, more specifically the period for which Mr. Lepage was performing additional duties for Énergir, L.P. It was paid by Green Mountain and reimbursed by Énergir, L.P. through the monthly fees described in Item 10.1.3.1 *Compensation Policies for Named Executive Officers* above. This amount also includes $2,546 of life insurance premiums, which were not deferred.
(11) The compensation of Mr. Lepage that is presented for the 2020 fiscal year corresponds to the compensation he received as Vice President, Chief Financial Officer and Treasurer of Green Mountain, said compensation was paid by Green Mountain.
(12) The 2021 Annual Information Form indicated Ms. Trudeau's salary for the January 1, 2021 to September 30, 2021 period. That amount was corrected in this Annual Information Form to reflect the salary for the October 1, 2020 to September 30, 2021 period.
(13) For fiscal year 2022, this amount includes a $32,000 discretionary incentive greater than that provided for in the *Compensation Policy for Senior Executives.*
(14) For fiscal year 2020, this amount includes a $30,000 discretionary incentive greater than that provided for in the *Compensation Policy for Senior Executives*.
(15) Salary includes the base salary paid by Green Mountain and the director's fees from VELCO, which are granted through the VELCO ownership structure by Green Mountain (38.8% interest in VELCO as at September 30, 2022). For fiscal year 2022, Ms. McClure received an annual base salary of $600,406 from Green Mountain, as well as fees of $24,139 as a director of VELCO until September 30, 2022.
(16) This amount represents a variation in the compensatory amount of Ms. McClure's 401(k) retirement plan.
(17) This amount represents $6,322 of life insurance premiums; no compensation was deferred.
(18) Salary includes the base salary paid by Green Mountain and the director's fees from VELCO, which are granted through the VELCO ownership structure by Green Mountain (38.8% interest in VELCO as at September 30, 2021). For fiscal year 2021, Ms. McClure received an annual base salary of $575,587 from Green Mountain, as well as fees of $24,139 as a director of VELCO until September 30, 2021.
(19) This amount represents a variation in the compensatory amount of Ms. McClure's 401(k) Plan.
(20) Represents $6,321 of life insurance premiums; no compensation was deferred.
(21) Salary includes the base salary paid by Green Mountain and the director's fees from VELCO, which are granted through the VELCO ownership structure by Green Mountain (38.8% interest in VELCO as at September 30, 2020). For fiscal year 2020, Ms. McClure received an annual base salary of $117,154 from Green Mountain as Executive Vice President until December 31, 2019 and $451,887 as President and Chief Executive Officer, as well as fees of $12,720 as a director of VELCO until September 30, 2020.
(22) This amount represents a variation in the compensatory amount of Ms. McClure's 401(k) retirement plan.
(23) Represents $2,892 of life insurance premiums; no compensation was deferred.

10.1.5 Termination and Change of Control Benefits

a) President and CEO of Énergir, L.P.

The current President and CEO, Mr. Lachance, is the only executive officer, including the other Named Executive Officers, who has an employment contract.

Mr. Lachance's employment contract provides for compensation in certain cases of termination of his employment, such as a termination of contract by or a change in the control of Énergir Inc. resulting in either a significant change in his responsibilities or a termination of his functions as President or the fact that he no longer reports directly to the Board. In such cases, should Énergir Inc. decide to terminate the contract, Mr. Lachance would be entitled to compensation equal to two years of his annual base salary as at the termination date. Should Mr. Lachance's responsibilities be reduced to any significant extent, such as in certain cases prescribed in the contract, he may resign and receive the same compensation. In either of the foregoing situations, Mr. Lachance would also be entitled to a pro rata portion of the bonus under the Annual Incentive Compensation and Long-Term Incentive Program for the current fiscal year.

Mr. Lachance's contract contains a confidentiality clause with respect to confidential information he received about Énergir Inc., its operations, its business and its subsidiaries during his employment. The contract also includes a provision, valid in any area of the province of Quebec, the Province of Ontario and the Northeastern United States whereby Mr. Lachance agrees not to provide his services directly or indirectly as an employee, officer, director, shareholder or consultant to an enterprise carrying on activities that compete with Énergir Inc. in the energy sector, without Énergir Inc.'s prior written consent, for a one-year period. A non-solicitation clause also applies for the same territory and the same period.

The following table shows the benefits that would have been paid to Mr. Lachance as a result of a termination of his employment or a change in control in the circumstances described above, assuming either of those events occurred on September 30, 2022:

Termination and Change of Control Benefits Table

Name	Termination of Employment Benefits ($)	Annual Incentive Compensation[1] ($)	Long-Term Incentive Program [1][2] ($)	Retirement Benefit [3] ($)	Employee and Indirect Benefits ($)
Éric Lachance President and CEO	1,121,258	302,403	981,101	—	—

(1) If the termination was before or after September 30, Mr. Lachance would be entitled to a prorated portion of the compensation for the current fiscal year.

(2) This amount represents the last instalment paid under the former long-term incentive program, as indicated in Item 10.1.3.7 *Long-Term Incentive Program.*

(3) Only the amounts accrued under the registered pension plan and the post-retirement allowance program are vested to the Named Executive Officer if there is a termination of employment. In the absence of assumptions prescribed for calculating the amount accrued under the Post-Retirement Allowance Program, the assumptions prescribed by the Canadian Institute of Actuaries ("**CIA**") for registered pension plans were used to determine the amounts accrued under both programs. Lastly, under the provisions of the post-retirement allowance program, Mr. Lachance would only be eligible for a deferred annuity, unless the Board were to grant another form of payment.

b) Other Named Executive Officers

In the event of termination or a change of control, the other Named Executive Officers of Énergir, L.P. do not have any specific agreement, and any amounts payable to them would be determined in accordance with applicable legislation and Énergir, L.P.'s policies at that time. The provisions of the executive officer compensation policy and those of the registered pension plan and the post-retirement allowance program establish certain payments in the case of termination of employment or a change in control.

Green Mountain's President and CEO, Ms. McClure, and Chief Financial Officer of Énergir, L.P, and Vice President, Chief Financial Officer and Treasurer of Green Mountain, Mr. Lepage, are not entitled to such benefits in the event of termination or change of the control. Mr. Lepage, however, has accumulated years of service for the purposes of Énergir, L.P.'s registered pension plan up to April 30, 2021. Should his employment be terminated, he would be entitled to the benefits accrued under that plan.

The following table shows the benefits that would have been paid to the other Named Executive Officers following termination of employment or a change in control, assuming termination of employment took place on September 30, 2022:

Termination and Change of Control Benefits Table

Name	Termination of Employment Benefits ($)	Annual Incentive Compensation[1] ($)	Long-Term Incentive Program [1][2] ($)	Retirement Benefit [3] ($)	Employee and Indirect Benefits ($)
Mathieu Lepage Chief Financial Officer[4]	—	—	—	275,900[5]	—
Stéphanie Trudeau Executive Vice President, Quebec	—	180,105	430,500	682,300	—
Renault-François Lortie Vice President, Customers and Gas Supply	—	144,807	252,788	271,700	—

(1) No Annual Incentive Compensation is payable unless the HR-SR Committee decides otherwise.

(2) Assuming as at September 30, 2022, the termination of employment of a Named Executive Officer, within 18 months following a change in control. During the fiscal year, the amounts owing are paid on a pro rata basis for the current fiscal year. These amounts represent the last instalment paid under the former long-term incentive program, as indicated in Item 10.1.3.7 *Long-Term Incentive Program.*

(3) Only the amounts accrued under the registered pension plan and the post-retirement allowance program are vested to the Named Executive Officer if there is a termination of employment. In the absence of assumptions prescribed for calculating the amount accrued under the post-retirement allowance program, the assumptions prescribed by the CIA for registered pension plans were used to determine the amounts accrued under the two programs. Lastly, under the provisions of the post-retirement allowance program, the Named Executive Officer would only be eligible for a deferred annuity, unless the Board grants another form of payment.

(4) As explained in Item 10.1.3.1 *Compensation Policies for Named Executive Officers*, Mr. Lepage is subject to Green Mountains compensation policy.

(5) This amount represents the value of the retirement benefits accumulated in Énergir, L.P.'s registered retirement plan up to April 30, 2021 since he was hired in September 2005.

10.1.6 Énergir Inc.'s Director Compensation Analysis

10.1.6.1 Director Compensation Policy

The CGEE Committee reviews as needed the compensation of directors (other than (i) the President and CEO, and (ii) the directors who are also regular CDPQ employees and do not receive any compensation as a director) and makes recommendations to the Board for approval. In developing its recommendation to the Board for appropriate director compensation, the CGEE Committee's objective is to attract and retain competent individuals to sit on the Board. The compensation has to be competitive and commensurate with the growing complexity of Énergir, L.P.'s activities as well as with the risks and responsibilities associated with a directorship at Énergir Inc. To determine the appropriate compensation to pay to the directors, the CGEE Committee does a market comparison with other listed Canadian corporations with assets or activities comparable to Énergir, L.P., and analyzes the director compensation practices of that comparison group following the compensation consultant's recommendations.

The director compensation program consists of an annual lump-sum cash fee, paid quarterly. Directors are also reimbursed for expenses they incur, in particular for travel to attend Board and committee meetings.

In fiscal year 2022, the HR-CG Committee, which then assumed the director compensation responsibilities now performed by the CGEE Committee, did not retain the services of a compensation consultant with respect to director compensation.

10.1.6.2 Director Compensation Components

The following table shows the components of director compensation during fiscal year 2022:

	Compensation
	Annual Fees ($)
Chair of the Board	225,000
Board member[1] (except the Chair of the Board)	80,000
Chair of Audit Committee[2]	20,000
Committee Chair[2]	12,000
Committee member[3]	12,000

(1) The President and CEO and the directors who are also regular CDPQ employees do not receive any compensation as a director.
(2) Excluding the Chair of the Board and the directors who are also regular CDPQ employees, if they chair a committee.
(3) Excluding the Chair of the Board and the directors who are also regular CDPQ employees, if they sit on a committee.

10.1.6.3. Director Compensation Table

The total compensation paid to the directors as members of the Board and various committees during fiscal year 2022 is presented in Item 9.1 *Directors*.

The following table details the director compensation for fiscal year 2022:

Director Compensation Details for Fiscal Year 2022

Name	Fees ($)	Other Compensation ($)	Total ($)
Renaud Faucher[1]	N/A	—	—
Ghislain Gauthier	225,000	—	225,000
Jean-Luc Gravel	92,000	12,000 [2]	104,000
Jean-Christophe Lincourt-Éthier[1]	N/A	—	—
Mary G. Powell[3]	92,000	—	92,000
Marie-Pier St-Hilaire	52,667	—	52,667
Keri Sweet Zavaglia[3]	23,000	—	23,000
Nathalie Viens[1]	N/A	—	—
Allen C. Capps[4][5]	23,000	—	23,000
Matthew Akman[4]	20,000	—	20,000
Cynthia Hansen[4][6]	26,000	—	26,000

(1) The representatives of the CDPQ who sit on the Board have waived their compensation as directors of Énergir Inc. and as members and chairs of its committees.
(2) On July 21, 2021, the Board abolished the Pension Fund Committee that had been created by the Board and entrusted most of the responsibilities it previously had to a new committee consisting of Management, namely the Investment Committee. In fiscal year 2022, as part of transitioning the Pension Fund Committee's responsibilities to the Investment Committee, Mr. Gravel, who was Chair of the Pension Fund Committee at the time it was abolished, participated in the Investment Committee as an invitee, for which he received $12,000 in compensation.
(3) Mses. Powell and Sweet Zavaglia are paid in U.S. dollars.
(4) Messrs. Capps and Akman and Ms. Hansen stepped down on December 31, 2021, and their compensation was prorated for the period from October 1 to December 30, 2021. Their compensation was paid to their employer, Enbridge.
(5) Mr. Capps' compensation includes his fees as member of the Audit Committee.
(6) Ms. Hansen's compensation includes her fees as Chair of the OHS-Env. Committee and member of the HR-CG Committee.

10.1.7. Loans to Directors and Named Executive Officers

As at September 30, 2022, there were no loans granted to directors, potential directors or any person related to such persons.

As at September 30, 2022, there were no loans granted to a Named Executive Officer or to a person related to such person, other than loans normally offered to all Énergir, L.P.'s employees under employee programs.

10.2 Additional Information

10.2.1 Governance Information

This information is provided as required by the Canadian corporate governance guidelines, namely, R*egulation 58-101 Respecting Disclosure of Corporate Governance Practices* and *Policy Statement 58-201 to Corporate Governance Guidelines* of the Canadian Securities Administrators, and *Regulation 52-110 respecting Audit Committees*. It is presented as at the date of this Annual Information Form.

10.2.1.1. Board of Directors

Énergir Inc.'s affairs are managed by its Board. The Board is made up of nine directors, six of whom are independent. Mr. Ghislain Gauthier is independent and chairs the Board.

For more information, please see Item 9.1 *Directors* of this Annual Information Form, which presents the directors' biographies and information on: (i) the independence of the directors; and (ii) the other reporting issuer directorships in or outside Canada, as the case may be.

The day-to-day management of Énergir Inc. is delegated to the President and Chief Executive Officer and the other officers, but is overseen by the Board. The Board develops a position description for the chair and the chair of each board committee. Their roles and responsibilities are described in Schedule 10.2.1.1 *Board of Directors - Mandate*. Moreover, the Board as well as the President and Chief Executive Officer have developed a written position description for the latter's position, which is available on Énergir, L.P.'s website at www.energir.com.

The Board holds quarterly meetings, which include one quarterly meeting focused more on strategy, and *ad hoc* meetings, as required. Given its composition, the Board feels it is unnecessary to hold regular periodic meetings without the non-independent directors. However, in camera sessions are held at the end of each meeting without Management in attendance.

<u>Attendance Record of Directors for Board and Committee Meetings</u>

The attendance record of each director for all Board and committee meetings held since the beginning of the most recently completed fiscal year of Énergir Inc., namely, October 1, 2022, is presented in Item 9.1 *Directors*.[34]

<u>Board Mandate</u>

The mandate of the Board is set out in Schedule 10.2.1.1 *Board of Directors - Mandate*. The role and responsibilities of the chair of the Board are described therein. The Board mandate was amended on October 18, 2022, and December 15, 2022, to add, among other things, provisions respecting the constitution and composition of the Board, the guests invited to meetings and the quorum required for Board meetings. The amendments to the Board mandate also reflect changes made to the committees' structure and the Executive Committee's abolition. The Board mandate, thus amended, also explicitly indicates the Board's oversight responsibilities where ESG factors and corporate risks are concerned.

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[34] Mr. Matthew Akman, Mr. Allen C. Capps and Ms. Cynthia Hansen ceased being directors during the fiscal year, namely on the effective date of December 30, 2021. Therefore, for the period between October 1, 2021 and December 30, 2021, (i) Mr. Matthew Akman partially participated in a Board meeting (a participation rate of 50%), (ii) Mr. Allen Capps did not participate in any Board meeting (a participation rate of 0%) and participated in an Audit Committee meeting (a participation rate of 50%), and (iii) Ms. Cynthia Hansen participated in a Board meeting, partially participated in another Board meeting (a participation rate of 100%), participated in three HR- CG Committee meetings (a participation rate of 100%) and participated in two OHS-Env. Committee meetings (a participation rate of 100%).

The following table sets out the Board's main responsibilities for fiscal year 2022 and highlights of the Board for fiscal year 2022.

Board of Directors	
Main Responsibilities	In fiscal year 2022, the Board's responsibilities included, among other things: • ensuring that management maintains a culture of integrity throughout the organization; • adopting a strategic planning process and periodically approving a strategic plan that addresses, among other things, business opportunities and risks; • identifying and monitoring the main risks faced by the enterprise and ensuring appropriate measures and systems are implemented for managing such risks; • planning the succession for senior executives; • developing Énergir Inc.'s approach to corporate governance; • periodically evaluating the effectiveness of the Board, its members, its chair, its committees and their members and chairs; • on a recommendation of the HR-CG Committee, establishing and approving the compensation policies and programs for management, evaluating the performance of the President and CEO based on the objectives set, and establishing his/her compensation; • with the assistance of the Audit Committee, ensuring compliance with accounting standards, as well as the integrity and adequacy of financial reporting; and • on a recommendation of the Audit Committee, adopting the interim and annual financial statements of Énergir Inc. and the annual financial statements of Énergir, L.P.
2022 Highlights	• supervising the strategic planning and annual strategic review, notably as regards decarbonization as well as merger and acquisition strategies; • reviewing the business risk assessment; • reviewing the cybersecurity positioning assessment; • reviewing the major energy and market trends; • reviewing the main events/changes for Énergir, L.P. and Énergir Inc.; • approving the interim and annual financial statements of Énergir Inc. and the annual financial statements of Énergir, L.P.; • approving the external audit plan, namely the Audit Planning Report for the fiscal year; • approving the (i) extension and amendment of the credit agreement, including the addition of Énergir, L.P. as co-debtor with Énergir Inc., (ii) transfer of Énergir Inc.'s commercial paper program to Énergir, L.P., and (iii) issuance and sale, by Énergir, L.P., of short term promissory notes; • approving the (actual) external audit fees; • approving the Climate Resiliency Report; • approving the private placement of first mortgage bonds; • approving 2022 strategic initiatives; • approving the Diversity, Equity and Inclusion in Employment Policy; • reviewing the new structure of the Board committees; and • analyzing the financial results of Énergir, L.P. and Énergir Inc.

The Board's responsibilities, as amended by the changes to its mandate on October 18, 2022, and December 15, 2022, appear in Schedule 10.2.11, *Board of Directors - Mandate.*

10.2.1.2 Orientation and Continuing Education

In fiscal year 2022, the HR-CG Committee was responsible for implementing a directors' education program ("**Education Program**") to promote the integration of new directors and support them in learning the fundamental aspects of the business in order to bring their understanding up to the level of other directors over a one-year period, and further deepen the knowledge of already existing directors from a continuing education perspective. Since October 18, 2022, the CGEE Committee has been responsible for this program.

The Education Program includes a component for new directors that deals with some of the more fundamental aspects of the business and targeted meetings with the vice presidents.

Each new director therefore participates in an official orientation program. The program consists of a series of meetings between the new director and the Board chair, the President and CEO, the chair of any standing committee on which the director may sit and other key Énergir, L.P. officers. Depending on the director's background and experience and the results of the meetings with officers, additional meetings may be organized.

In addition to these meetings, the new director has access to the Énergir Inc. Director's Manual, which is posted on a secure portal dedicated to the directors. The Manual includes, among other things, information on Énergir, L.P. and Énergir Inc., a summary of Énergir Inc.'s directors' and officers' liability insurance coverage as well as a summary of the duties, obligations and responsibilities of a director and the Board. The portal also contains, among other materials, a full set of documents containing public and private information on Énergir, L.P. and Énergir Inc., which documents provide detailed information on the business, including on its strategic plan, operations, financial situation and management structure; its corporate policies, basic texts and continuous disclosure documents; the work plans, mandates and minutes of the meetings of the Board and its committees; as well as biographical information on Board members and key executives of Énergir, L.P. This portal is updated regularly.

Another component of the Education Program is for all directors, new and experienced, and consists of various training sessions offered over the course of a year that focus more on the business's activities and operations, as well as the environment in which it evolves.

The Board ensures that directors are familiar with the activities of Énergir, L.P. and the industry through information provided by Management and external sources. Management is also always available for information sessions for directors. Moreover, the Board encourages directors to update their energy and governance related knowledge through attendance at conferences, seminars or workshops. In this regard, Management or invited speakers periodically update the directors on the main issues, projects, challenges and prospects for Énergir, L.P. or the energy industry.

All directors are also members of the Institute of Corporate Directors ("**ICD**"), which gives them access to publications and activities enabling them to develop their knowledge of director obligations and current trends in corporate governance. The ICD contributes to the development and promotion of good governance and corporate governance best practices.

The following table shows the various trainings offered by Énergir, L.P. that the directors attended in fiscal year 2022.

Board	Subject
February	Dual Energy: Operationalization and launch of offering
April	Major human resource trends and cultural evolution
May	New climate plan in Vermont and impacts on the strategic outlook of Green Mountain and Vermont Gas
May	Tour of the École de technologie gazière
May	Occupational health and safety, environment and the Process Safety Management System - Key operational trends
May	2022 economic outlook
May	Research file: Carbon capture, sequestration and utilization

10.2.1.3 Organizational Ethics

The Board has adopted a Code of Ethics for directors, officers and employees of Énergir, L.P. and its Quebec and Canadian subsidiaries and for any person or enterprise hired to represent them.

The Code of Ethics is distributed to all new directors, as well as the officers and employees of Énergir, L.P. It is also available on the portal dedicated to the directors, on Énergir, L.P.'s intranet site, to which every employee has access, and on Énergir, L.P.'s website. Furthermore, in accordance with Section 2.3 of *Regulation 58-101 Respecting Disclosure of Corporate Governance Practices of the Canadian Securities Administrators*, a copy of the *Code of Ethics* is available on the SEDAR website at www.sedar.com.

The *Code of Ethics* invites any individual to whom it applies who has reason to believe that a director or employee is not complying with the provisions of this Code to anonymously report the situation, at no cost, through *ClearView Connects,* as provided for in the *Policy on the Reporting and Handling of Public and Employee Complaints.* For more information on this subject, please refer to Item 10.2.5 *Complaints or Concerns*.

All employees of Énergir, L.P. are required to take an online ethics training course called "Ethics in Action." This interactive training course is available on Énergir, L.P.'s human resources portal. When the training course has been completed by the employee, proof of participation is entered in his or her training record. Follow-up is conducted each quarter with the managers to ensure that the training course has indeed been completed by all employees. Unionized employees also take an ethics training course. An annual commitment reminder was also implemented to raise awareness of specific ethical behaviours. The purpose of this reminder is to ensure that each employee develops an ethical culture and commits to complying with the *Code of Ethics*. For the year 2022, the annual commitment reminder was completed through an ethics survey that was sent to all employees.

Employees are also consulted to guide organizational actions and identify what measures can be taken in priority to provide support and ensure that a culture of ethical conduct is always promoted within the corporation. Managers and employees all participate in ethical awareness and learn about the conduct that is expected of them by means of testimonials or group discussions, among others.

In addition, at the time of hiring, all new employees are required to sign a form in which they acknowledge the provisions of the *Code of Ethics* and undertake to comply therewith. The directors, the executive officers and the presidents of the Quebec and Canadian subsidiaries sign an attestation annually as regards their commitment to comply with the *Code of Ethics*. The managerial personnel in the Goods and Services Procurement Department Administration Contractor Agreements annually sign a form in which they acknowledge Énergir's ethics and undertake to comply therewith. The attestation process promotes integrity as a core value.

The rules of conduct for directors and executive officers are clearly set out in Énergir Inc.'s By-Laws, particularly as they apply to conflicts of interest and to their disclosure. Each director is required to inform the Board of any real, potential or apparent conflict of interests with Énergir, L.P. Directors may not participate in deliberations during which any matter that could affect their interest is discussed, must avoid influencing the vote and must abstain from voting on such matters.

Accordingly, any director or executive officer who has an interest in a contract or a transaction to which Énergir Inc. or Énergir, L.P. is party is required to disclose this fact in accordance with the Énergir Inc. By-Laws. Such director is also required to disclose any contract or transaction to which is party Énergir Inc. or Énergir, L.P. and (i) a person related to him/her, (ii) a group (within the meaning of the *Business Corporations Act* (Quebec)) of which he/she is a director or officer, and (iii) a group in which he/she has an interest or in which a person related to him/her has an interest.

The Chair of the Board shall ensure compliance with these rules in consultation with the Corporate Secretary.

Moreover, directors and executive officers have to submit an annual declaration of their outside positions and interests informing the Chair of the Board and the President and Chief Executive Officer of any potential conflicts of interest. The Chair of the Board shall report thereon to the CGEE Committee. The CGEE Committee monitors and manages actual or potential conflicts of interest involving directors and officers.

Other steps the Board has taken to encourage and promote a culture of ethical business conduct include the adoption of the business Mission, a corporate policy stating the values of Énergir, L.P. that is promoted inside the organization. It deals, among other things, with relations with customers, communities and players in the energy sector and society in general.

10.2.1.4 Nomination of Directors

The Board has adopted Guidelines for Recruiting and Renewing Directors of Énergir Inc. (the "**Guidelines**") for the selection and recruitment of candidates for nomination to the Board and to favour renewal within the Board. The aim of these Guidelines is to recruit dedicated, qualified candidates with an exemplary reputation who will add to the Board's expertise in order that it may carry out Énergir, L.P.'s business strategy.

Directors are appointed either directly by Noverco, or by the Board, with the consent of Noverco, if there is a vacancy between two annual meetings. The CGEE Committee, based on the Guidelines, reviews the composition of the Board and provides the sole shareholder with its opinion as to the size of the Board, nominated candidates or individuals who should be considered as candidates by Noverco. If there is a vacancy, the CGEE Committee will examine the candidates nominated by Noverco to replace a director and submit a recommendation to the Board.

10.2.1.5 Compensation of Directors and Executive Officers

The compensation of the directors is fixed by the Board, on the recommendation of the CGEE Committee, which carries out periodic benchmarking and, when it deems fit, uses studies published by compensation specialists for this purpose. The primary responsibilities of the CGEE Committee are described in Item 10.2.1.6 *Committees of the Board*.

The compensation of executive officers is fixed by the Board, on the recommendation of the HR-SR Committee based on the *Compensation Policy for Senior Executives*. Readers are urged to consult Item 10.1 *Report on Executive Officer and Director Compensation* of this Annual Information Form, which deals with executive compensation.

10.2.1.6 Committees of the Board

For the composition of the Board committees during fiscal year 2022, please see Item 9.1 *Directors*.

In fiscal year 2022, the Board committees were as follows: the HR-CG Committee, the OHS-Env. Committee, the Audit Committee and the Executive Committee.

The following table indicates fiscal year 2022 highlights of the HR-CG Committee and the OHS-Env. Committee:

2022 Highlights	
HR-CG Committee	• reviewing the results of 2021 strategic initiatives; • recommending that the Board approve the 2022 strategic initiatives; • examining the five-year salary movements - middle management, specialized personnel and unionized employees; • evaluating the performance of the President and CEO; • reviewing progress made in DEI within the business; • recommending the Diversity, Equity and Inclusion in Employment Policy to the Board; • reviewing the status on labour relations; and
OHS-Env. Committee	• monitoring and managing the impacts of COVID-19, including the procedures and initiatives implemented to ensure the safety and well-being of all, and supervising the gradual return to the office; • monitoring the process safety management system approach; • monitoring the psycho-social risk assessment process; • monitoring the analysis of the ESG approach and the priority ESG topics; • monitoring the third-party damage prevention program; • examining the Climate Resiliency Report and recommending its approval to the Board; • reviewing the results of the absolute GHG emissions for fiscal year 2021; and • reviewing the quarterly and annual environmental reports and occupational health and safety reports.

Since October 18, 2022, the Board committees are as follows: the CGEE Committee, the HR-SR Committee and the Audit Committee.

CGEE Committee

The Board has a nominating committee, the CGEE Committee, composed of directors who are independent in accordance with the independence requirements of Regulation 52-110, except for Ms. Mary G. Powell, who is not independent. The Board is of the opinion that Ms. Powell is able to exercise the impartial judgment needed to fulfill her responsibilities as a CGEE Committee member, and that her appointment is in the best interests of Énergir Inc. The other members of the CGEE Committee are Messrs. Jean-Luc Gravel (Chair) and Jean-Christophe Lincourt-Éthier.

The CGEE Committee's mandate can be consulted on Énergir, L.P.'s website at www.energir.com. This mandate was approved on October 18, 2022, and amended on December 15, 2022. It attributes to the CGEE Committee the corporate governance responsibilities previously assumed by the HR-CG Committee, the environmental responsibilities previously assumed by the OHS-Env. Committee, as well as responsibilities relating to complaints and ethical concerns previously assumed by the Audit Committee, and further develops these responsibilities. New ethical and legal compliance responsibilities were also added.

The operation of the CGEE Committee is described in its mandate. The CGEE Committee meets four times a year on the dates and at the times and places determined by the Board.

The following table indicates the main responsibilities of the CGEE Committee.

CGEE Committee	
Main Responsibilities	The CGEE Committee's responsibilities include, among other things: • reviewing Énergir Inc.'s and Énergir, L.P.'s approach to corporate governance as well as the practices and procedures used for applying the approach in this area, including the Board's adoption of corporate policies that the Board did not specifically delegate to another Board committee, seeing to the implementation thereof and ensuring that they are updated with the President and CEO and Corporate Secretary, and submitting recommendations to the Board; • reviewing reports from Management on the identification and analysis of corporate governance, ethics and environmental risks; • recommending to the Board the overall profile of qualifications and experience sought on the Board for the selection of Board members; • determining and submitting to the Board for approval the process for the recruitment of qualified persons to stand for election to the Board at a meeting of shareholders or for appointment by the Board to fill any vacancy on the Board; • developing the criteria to be considered for the selection of candidates for the position of Director, in accordance with the Guidelines; • proposing to the Board, for recommendation to Noverco, the number of members on the Board and the number of members who are not related to Noverco; • recommending to the Board the names of the Directors who will sit on the committees of the Board as well as the names of the Directors who will chair the committees; • recommending to the Board the compensation of its members, committee members, committee Chairs and the Chair of the Board; • reviewing from time to time matters addressed by the Board and the Committees, the quality of the documentation provided, the organization and the frequency of meetings, the quality of follow-up of decisions by Management as well as the methods and the quality of the communications between the Directors and Management; • developing, updating and evaluating the effectiveness of the initial and continuing education for Board members; • on a yearly basis, reviewing the diversity on the Board and the impact of the steps taken towards achieving the objectives set by the Board, reporting to the Board and proposing any adjustments that may be required; • overseeing and reviewing Énergir, L.P.'s approach to ethics and making recommendations to the Board as appropriate; • reviewing and evaluating, on a periodic basis, the effectiveness of management's ethics practices, discussing this with the President and CEO and the Corporate Secretary and reporting thereon to the Board; • overseeing procedures for the receipt, retention and treatment of any complaints and concerns received by Énergir, L.P. regarding ethics and compliance, and investigating such complaints and concerns; • reviewing changes in legislation that may materially affect Énergir, L.P. and its subsidiaries and receiving, on an annual basis, the report on compliance with legislation applicable to Énergir, L.P. and its subsidiaries; • receiving and reviewing environmental strategies, best practices and trends, and making recommendations to the Board as required; • reviewing and monitoring from time to time the environmental actions, targets, performance indicators and objectives included in Énergir, L.P.'s ESG plan or identified by Énergir, L.P.; • receiving a quarterly report on Énergir, L.P.'s environmental performance to ensure its operations comply with industry standards and the standards imposed by the applicable laws and regulations; • receiving and reviewing, on a quarterly basis, the CATS report; • as required, reviewing the year's strategies, plan and priorities in relation to the Sustainability Report and the Climate Resiliency Report; • receiving and reviewing the Sustainability Report, the Climate Resiliency Report and the sections of the Annual Information Form for which it is responsible and recommending their approval to the Board; • presenting periodic reports and making recommendations on significant environmental matters; and • reviewing Énergir, L.P.'s Environmental Policy and recommending the approval thereof to the Board.

HR-SR Committee

The following table indicates the main responsibilities of the HR-SR Committee. The members of the HR-SR Committee are Renaud Faucher, Ghislain Gauthier (Chair), Keri Sweet Zavaglia and Nathalie Viens.

HR-SR Committee	
Main Responsibilities	The HR-SR Committee's responsibilities include, among other things: • reviewing reports from management on the identification and analysis of human resource and social responsibility risks; • managing, when required, the recruiting process for a President and CEO; • recommending to the Board the appointment of a candidate for the position of President and CEO; • on a yearly basis, reviewing the diversity within management and the impact of the steps taken to achieve the objectives set by the Board, reporting to the Board and proposing required adjustments, if applicable; • reviewing the corporate objectives proposed by the President and CEO as well as the President and CEO's proposals for the objectives of the executive officers, and submitting recommendations to the Board; • reviewing and approving the performance evaluation policies and processes for senior executives and other management personnel; • evaluating the performance of the President and CEO against the objectives set at the beginning of the fiscal year; • reviewing the report prepared by the President and CEO evaluating the performance of the executive officers reporting to him; • reviewing the global compensation policy for executive officers, including that of the President and CEO, and ensuring that the compensation to be paid (including incentive compensation based on the performance evaluation) complies therewith, recommending any changes it deems desirable and making its recommendations to the Board; • recommending to the Board appropriate compensation packages in light of the benefits and risks associated therewith, including the risks associated with ESG factors; • reviewing the benefit plans and receiving an annual report on the evolving costs thereof; • reviewing a report on the status of labour relations for staff governed by collective bargaining agreements, including a follow-up on current negotiations and/or the outcome of negotiations with respect to such collective bargaining agreements; • reviewing and deciding on the pension plans of management personnel and employees governed by a collective agreement as well as matters relating to the utilization of any actuarial surplus and contribution holidays; • ensuring that there are adequate succession planning mechanisms for executive officers, including the President and CEO, and ensuring that the succession plan is updated annually and that programs are used to identify, develop and retain executive officers and their successors, particularly for senior executives; • reviewing the orientation of human resource management policies and ensuring the existence of adequate human resource systems for recruiting, motivating and retaining executive officers and employees who exhibit high standards of integrity and competence; • ensuring that Énergir, L.P.'s human resource practices and organizational culture are aligned with its ESG practices and strategies; • receiving and reviewing strategies, best practices and trends in social responsibility, including occupational health and safety, and making recommendations to the Board, as appropriate; • reviewing and monitoring, as appropriate, the corporate social responsibility actions, targets, performance indicators and objectives included in Énergir, L.P.'s ESG Plan or identified by Énergir, L.P.; and • receiving and reviewing reports from management on the Énergir, L.P.'s accident and workplace safety performance in order to ensure, among other things, that Énergir, L.P.'s activities comply with industry standards and the standards imposed by the applicable laws and regulations, and that Énergir, L.P. is adopting best practices in the prevention of work-related accidents.

The HR-SR Committee's mandate is available on Énergir, L.P.'s website at www.energir.com. This mandate was approved on October 18, 2022, and amended on December 15, 2022. Among other things, it attributes to the HR-SR Committee the human resources and community impact responsibilities previously assumed by the HR-CG Committee and the occupational health and safety responsibilities previously assumed by the OHS-Env. Committee, and further develops these responsibilities. The new mandate also explicitly incorporates the HR-SR Committee's responsibility for ESG factors.

<u>Audit Committee</u>

For an overview of the Audit Committee, please refer to Item 10.2.2 *Audit Committee Information.* The Audit Committee table is presented in Item 10.2.2.1 *Relevant Education and Experience*.

<u>Executive Committee</u>

In fiscal year 2022, an Executive Committee was in place that held all of the Board powers attributed to it under Énergir Inc.'s by-laws. This committee did not meet in fiscal year 2022 and was abolished by the Board on October 18, 2022.

10.2.1.7 Evaluation

The HR-CG Committee has implemented an annual process for assessing the effectiveness of the Board, its committees and their Chairs and a peer assessment for each director. The entire assessment process was benchmarked to the latest practices advocated by corporate governance authorities and to certain issuers.

The questionnaires are developed by the Chair of the Board jointly with the Corporate Secretary. This assessment, which is performed on an anonymous basis, has been overseen by the CGEE Committee since October 18, 2022.

Under the process, after the results of the assessments have been compiled, they will be discussed by the Board, and each committee will review the assessments of its specific activities. The Board and the committees will then decide on the steps to be taken, based on the assessment results, to improve their effectiveness, if necessary.

In addition, the Chair of the Board will meet with each director in order to discuss his/her overall assessment and his/her perceptions regarding the contributions of the other members of the Board and committees. During that meeting, the directors also have the opportunity to discuss any matter they deem relevant with the Chair.

10.2.1.8 Director Term Limits and Other Mechanisms of Board Renewal

As discussed under Item 10.2.1.4 *Nomination of Directors*, the Board has adopted the Guidelines, which provide a framework for the approach to selecting and recruiting directors for the Board. The Guidelines set a term of 12 years of continuous service after which directors may not sit on the Board. However, this criterion may be adjusted in response to contexts and circumstances, based on the intermittent needs of the Board wishing to retain a director's expertise beyond such term limit.

To guarantee adequate Board renewal, the CGEE Committee is responsible for assessing the directors, the Board and the committees. The term limit and performance of each director and the composition and effectiveness of the Board and its committees are stringently assessed. An expertise and profile grid in the form of a table is used to verify that the Board has the necessary professional and operational experience, expertise and knowledge to administer Énergir Inc. effectively. The representation of women on the Board and its committees is also reviewed as part of the assessment.

10.2.1.9 Diversity and Inclusion

This item is presented in three parts: (i) the Diversity, Equity and Inclusion in Employment Policy; (ii) the Policy Regarding Diversity on the Board of Directors; and (iii) the representation of women in executive officer appointments. The last two are presented in accordance with Form 58-101F1 of *Regulation 58-101 Respecting Disclosure of Corporate Governance Practices*.

<u>i) Diversity, Equity and Inclusion in Employment Policy</u>

Énergir, L.P. has made it its mission to reflect not only the community in which it operates, but also where its customers live and work. Diversity and inclusion are part of the values and culture of Énergir, L.P.

Énergir, L.P. reinforced its commitment to diversity and inclusion by adopting (in 2013) and updating (in June 2019) an equal access to employment policy and publishing the *Code of Ethics*, which upholds the importance of ensuring employment equity while also confirming its commitment to promoting diversity and inclusion in the workplace.

In addition to this, Énergir, L.P. adopted a positioning in 2020 that very clearly seeks to encourage dialogue, deepen its analysis and nurture an openness to difference. Énergir, L.P. intends to promote DEI by:

- creating a workplace where everyone feels at ease and free to be themselves without fear of being judged, excluded or penalized, the whole subject to the Code of Ethics and other applicable corporate policies and guidelines;
- creating conditions where everyone is able to contribute and reach their full potential;
- raising awareness of the positive impacts of diversity and inclusion; and
- demonstrating that inclusion is a powerful driver of development for the business.

In August 2020, in support of Énergir, L.P.'s commitment to diversity and inclusion, Management approved its first annual action plan. This action plan was pursued in 2022, and several initiatives have been carried out since 2020. For more information on the subject, please refer to Item 5 *Human Resources Management.*

On August 4, 2022, the Board approved the Diversity, Equity and Inclusion in Employment Policy. This policy applies to Énergir, L.P. and all of its employees. It provides that the responsibilities for creating an even more inclusive workplace within Énergir, L.P. are shared by different stakeholders, including the Board and its committees, certain executive officers and the managers.

Énergir, L.P. will pursue its commitment to diversity and inclusion within the organization, given that diversity and inclusion can only enrich its organizational culture.

ii) Policy Regarding Diversity on the Board of Directors

In November of 2015, the Board adopted a written policy regarding diversity called *Policy Regarding Diversity on the Board of Directors* (the “**Diversity Policy**”) This policy sets representation targets and measures for attaining them.

The Board believes that it is essential to include gender, age and cultural representation characteristics of the communities in which Énergir, L.P. carries on its activities. As indicated above, Énergir, L.P. has made it its mission to reflect the community in which it operates, but also where its customers live and work. Having a broad range of candidates with diverse backgrounds and perspectives can only have a positive effect on the direction taken by the Board and, consequently, the sound management of the business.

That is why, under the Diversity Policy, the Board has made it an objective to strive for parity between men and women among the directors. The Board also set itself the target that at least 30.0% of its directors must be women.

In fiscal year 2022, Énergir Inc. exceeded its 30.0% target. The number of women directors rose to 44.44%, compared to 33.3% in 2021. There are currently four women on the Board: Mary Powell, Marie-Pier St-Hilaire, Keri Sweet Zavaglia and Nathalie Viens. Women therefore account for 44.44% of the nine directors.

Candidates

As Énergir Inc. is a controlled corporation, the appointment of directors falls to its controlling shareholder, Noverco. In this context, the Board only has the power to recommend candidates to its controlling shareholder, which ultimately has the last word on the choice of directors.

Given this situation, in order to achieve its objectives, Énergir Inc. has set out in the Diversity Policy that the CGEE Committee shall recommend to the controlling shareholder that it take into account Énergir Inc.’s objectives with respect to the representation of women when selecting candidates to fill director position vacancies. Furthermore,the Board recommends to the controlling shareholder that it evaluate candidates on their merits and taking into consideration the benefits of diversity and the needs of the Board. Gender diversity is one of the selection criteria under the Guidelines. The representation of women is therefore considered in recruiting new directors so as to enable the Board to achieve its objectives of striving for parity and maintaining the percentage of women directors at 30.0% or more.

In accordance with the Diversity Policy, the CGEE Committee assesses diversity on the Board annually. It also assesses the impact of the means deployed to achieve the objectives set by the Board.

The CGEE Committee reports to the Board, while proposing new measures or adjustments to already existing measures. Further to that report, the Board then assesses diversity in director positions. Taking into account the recommendations of the committee, it then determines new measures to be taken or adjustments to be made to better meet its needs in achieving its objectives.

Furthermore, in order to determine Board requirements when new directors are selected, the CGEE Committee maintains an up-to-date grid showing the various profiles and areas of expertise of the directors in office, including their gender and term limit.

iii) Representation of Women in Executive Officer Appointments

The Board believes that it is also essential to include diversity characteristics among the executive officers. The objective is to strive for parity in management positions, which include the position of President and Chief Executive Officer, the Vice President positions and the executive director positions.

In order to achieve the objective of striving for parity, Management implemented an annual diversity and inclusion action plan including internal and external steps that will lead, among others, to an increased representation of women in Énergir, L.P. management.

As at September 30, 2022, women accounted for 27.7% of management positions. Indeed, three of Énergir, L.P.'s eleven executive officers are women: Claudine Beaudet, Nathalie Longval and Stéphanie Trudeau. In the case of Green Mountain, a material subsidiary of Énergir, L.P., three of the eight executive officers are women: Mari McClure, Kristin Carlson and Liz Miller. Women therefore account for 31.58% of the executive officers of Énergir Inc. and its material subsidiary.

10.2.2 Audit Committee Information

The Audit Committee assists the Board in discharging its oversight responsibilities for accounting, information technologies and financial reporting processes, internal control systems and financial and risk management.

The mandate of the Audit Committee is reproduced in Schedule 10.2.2 *Audit Committee - Mandate*. This mandate was amended on October 18, 2022, and on December 15, 2022, for the purposes, among other things, of clarifying the Audit Committee's responsibility for monitoring corporate risks and transferring all responsibility for complaints and ethical concerns to the CGEE Committee. New privacy and information technology responsibilities (including cybersecurity) have also been added.

The Audit Committee is composed of four directors who are all financially literate and independent in accordance with Regulation 52-110, except for Mr. Renaud Faucher.

The Board relied on the exemption set forth in section 6.1 of Regulation 52-110 so as to allow Mr. Faucher to chair the Audit Committee. The flexibility afforded under section 6.1 allows venture issuers like Énergir Inc. to be exempted from the requirements of Parts 3 (Composition of the Audit Committee) and 5 (Reporting Obligations) of Regulation 52-110, which stipulates that every audit committee member must be independent.

For more on the composition of the Audit Committee, please refer Item *9.1 Directors* of this Annual Information Form.

10.2.2.1 Relevant Education and Experience

The following tables provide a brief description of the education and experience of each member of the Audit Committee that are relevant to the performance of his responsibilities as an Audit Committee member.

<table>
<tr><th colspan="3">Renaud Faucher</th></tr>
<tr><td colspan="3">Mr. Faucher holds a bachelor of civil engineering from École Polytechnique de Montréal, as well as an MBA from Concordia University and a DESS (specialized graduate diploma) in accounting from ESG-UQAM. He is also a Chartered Professional Accountant (CPA, CMA). From 1998 to 2006, he held various positions within subsidiaries of Hydro-Québec, including Director Investments, Vice President Finance and Vice President Risk Management. In 2006, he joined the CDPQ, where he is currently Managing Director, Infrastructure, North America. Over the course of his career, he has sat on the audit committees of several companies in the airport, pipeline, electricity transmission and health sectors. He currently chairs the audit committee of Colonial Pipeline Company. He was a member of the audit committee of Heathrow Airport Holdings for eight years, including four years as chair.</td></tr>
<tr><td>Attendance at meetings of the Audit Committee during fiscal year 2022</td><td>5/5</td><td>100%</td></tr>
</table>

Jean-Christophe Lincourt-Éthier		
Mr. Lincourt-Éthier holds a bachelor's degree in business administration (with specialization in finance and accounting) from HEC Montréal and is a member of the Ordre des CPA du Québec. He joined the CDPQ in 2012. He is currently Director, Infrastructures where he is responsible for the management of investments in North America in the energy sector and public transport. From 2015 to 2018, he participated in the creation of the CDPQ Infra subsidiary and in the development of the REM, a 67-km light rail metro in the greater Montreal area. From 2018 to 2021, he took over the financial operations of the REM, in addition to sitting on the boards of directors of REM Commandité Inc., Réseau express métropolitain Inc. and InfraMTL Inc. as an executive. Before joining the CDPQ, Mr. Lincourt-Éthier participated in the financing of infrastructure projects at SNC-Lavalin Capital, including the Restigouche Hospital Center in New Brunswick, the Highway 407 Extension in Ontario and the McGill University Health Centre in Montreal. He also sits on the board of directors of Immeuble VDS inc., a subsidiary of CDPQ Infra.		
Attendance[(1)] at meetings of the Audit Committee during fiscal year 2022	3/3	100%

[(1)] Mr. Lincourt-Éthier attended all Audit Committee meetings held after he was appointed director of Énergir Inc. on January 26, 2022.

Marie-Pier St-Hilaire		
Ms. St-Hilaire holds a bachelor's degree in corporate management and an MBA (with specialization in information technology) from Université Laval, and graduated from the Owner/President Management Program at Harvard Business School. In 2000, Ms. St-Hilaire founded AFI Expertise, currently one of the corporate names of Groupe Edgenda inc., for which she has acted as president since 2017. In that role, she is reinventing the traditional world of organizational transformation consulting by placing skills development at the heart of business strategies. Over the past 20 years, she has been able to achieve her entrepreneurial vision and produce organic, continuous, and profitable growth for her company. She has also led several acquisitions, including that of Apprentx, which, with its B12 application, has consolidated the group's position as the Canadian leader in skills development. Ms. St-Hilaire currently sits on the boards of Amerispa (since April 2022) and Entrepreneuriat Laval (since September 2021).		
Attendance[(1)] at meetings of the Audit Committee during fiscal year 2022	2/2	100%

[(1)] Ms. St-Hilaire attended all Audit Committee meetings held after she was appointed director of Énergir Inc. on February 24, 2022.

Nathalie Viens		
Ms. Viens holds a bachelor's and master's degree in chemical engineering from École Polytechnique de Montréal as well as a professional engineering certificate for the province of Quebec. Ms. Viens is also a certified project management professional (PMP) and a certified board member (ASC & C. Dir). She has been an Operating Partner supporting the global portfolio of the CDPQ's Infrastructure group since August 2020. Prior to joining the CDPQ, Ms. Viens held various management positions in large corporations, most notably as Senior Vice-President of Operations for Eastern Canada at Veolia North America, as Vice-President responsible for activities related to the mining environment as well as mine and plant engineering for SNC-Lavalin's North American Mining and Metallurgy group, and as Senior Manager in charge of multiple programs and service offers at Accenture. During her career, she was responsible for the administration of large diversified and multisite portfolios. Ms. Viens currently sits on the following boards of directors: Noverco, Transportadora Associada de Gás S.A., Student Transportation of America, Plenary Americas and FiBrasil. She is also President and Chair of the French Chamber of Commerce and Industry in Canada (CCIF).		
Attendance at meetings of the Audit Committee during fiscal year 2022	4/5	80%

The following table indicates the main responsibilities and fiscal year 2022 highlights of the Audit Committee.

Audit Committee	
Main Responsibilities	The Audit Committee's responsibilities include, among other things: • ensuring that adequate and rigorous financial and information technology controls are in place; • reviewing reports from the management with respect to the identification and analysis of the financial risks that may affect the corporation and the risks related to information technologies, including cybersecurity; • supporting the Board in its semi-annual review of management's report on integrated management of risks and opportunities for the entire business; • reviewing each quarter the report on information technology projects and priorities, cybersecurity and the physical security of the facilities; • reviewing periodically the report on compliance with respect to personal information to ensure that its practices comply with industry standards and the standards imposed by the applicable laws and regulations; • reviewing and monitoring the actions, targets, performance indicators and governance objectives related to physical and digital robustness and resilience included in Énergir, L.P.'s ESG plan or identified by Énergir L.P.; • ensuring oversight of the process safety approach and of the process safety management system; • ensuring the effectiveness of internal controls; • assuming responsibilities in respect of the external audit; • monitoring the integrity and quality of the internal control systems, the financial reporting process and accounting policies through investigations and discussions with management, the internal auditor and the external auditor; • in collaboration with the CGEE Committee, reviewing the corporate policies with respect to financial reporting and, if it deems appropriate, those concerning information technology, and the related follow-up being done; • reviewing the financial forecasts communicated by the management of Énergir, L.P. to the Board and ensuring that adequate controls and procedures are established and maintained by the management of Énergir, L.P. to ensure the integrity of these financial forecasts; • reviewing the annual information forms, prospectuses, as well as the interim and annual financial statements and MD&A of Énergir Inc.; and • on a quarterly basis, reviewing the internal audit activities report with the external and internal auditors.
2022 Highlights	• approving the financial statements of Énergir, L.P.; • recommending to the Board that it approve the MD&A and financial statements of Énergir Inc.; • approving the external audit plan, namely the *Audit Planning Report for the Fiscal Year;* • following up on the internal audit activities and reviewing its mandate; • reviewing the annual quality-control of the audit; • reviewing the internal control and internal audit reports; • reviewing reports on managing corporate risks; • reviewing reports on information technology projects and priorities, as well as cybersecurity; • recommending to the Board that it approve the (i) extension and amendments of the credit agreement, including the addition of Énergir, L.P. as co-debtor with Énergir Inc., (ii) transfer of Énergir Inc.'s commercial paper program to Énergir, L.P., and (iii) issuance and sale, by Énergir, L.P., of short term promissory notes; • filing reports, including tax and legal records, the procedure for handling complaints and concerns and the annual report on the Committee's compliance with the applicable regulations and policies.

During fiscal year 2022, all the recommendations of the Audit Committee to nominate or compensate the external auditor were adopted by the Board.

10.2.2.2 Pre-approval Policy and Procedures

The Audit Committee considered the question of whether the provision of services other than audit services is compatible with maintaining the independence of Énergir Inc.'s and Énergir, L.P.'s independent external auditors. The Audit Committee has adopted the *Policy and Procedure Regarding Pre-approval of External Audit and Non-Audit Related Services* (the "**Pre-approval Policy**"), which it reviews periodically. This Pre-approval Policy covers three types of services: (i) external audit or external audit-related services, (ii) external non-audit services that are allowed, and (iii) external non-audit services that are not allowed. In accordance with securities regulations, the Pre-approval Policy requires that all services rendered by the external auditors be pre-approved by the Audit Committee or, depending on the circumstances, its chair.

Furthermore, the Pre-approval Policy prohibits Énergir Inc. and Énergir, L.P. from retaining the services of the external auditors for certain non-audit services, including: bookkeeping services; design and implementation of information systems; valuation services, fairness opinions or reports on contributions in kind; actuarial services;

internal audit outsourcing services; management functions; human resources services; brokerage, investment consulting or investment banking services; and legal services.

In accordance with securities regulations, the Pre-approval Policy allows for a de minimis waiver for certain of the external non-audit services listed. If Management uses this waiver, it must promptly disclose this fact to the Audit Committee and publicly disclose it to the extent Énergir Inc. is required to do so by securities regulations, including Regulation 52-110. Management did not use this waiver in fiscal year 2022.

Each quarter, the external auditors provide to the Audit Committee a report on external audit services, external audit-related services and external non-audit services that are allowed that it provided as a result of the prior authorization granted by the Audit Committee or its chair or under the de minimis waiver, as the case may be, as well as the actual fees received in respect of such services.

For fiscal year 2022, all services rendered by the independent external auditors, be they audit or non-audit services, were pre-approved by the Audit Committee or its chair.

10.2.2.3 External Auditors' Fees

Énergir Inc.

The following table shows, by category, the fees invoices to Énergir Inc. by KPMG for its services for fiscal years 2022 and 2021:

Fees (by category)	2022 ($)	2021 ($)
Audit fees	139,977	132,680
Audit related fees	14,445	—
Tax fees	1,635	27,160
All other fees	—	—
Total	**156,057**	**159,840**

Audit fees include the total fees invoiced for the audits of the annual consolidated and non-consolidated financial statements, and the services related to quarterly reports and other documents to be filed with the Canadian Securities Administrators.

Énergir, L.P.

The following table shows, by category, the fees invoiced to Énergir, L.P. by KPMG for its services for fiscal year 2022 and 2021:

Fees (by category)	2022 ($)	2021 ($)
Audit fees	1,918,296	1,953,033
Audit related fees	148,899	115,142
Tax fees	—	—
All other fees	—	—
Total	**2,067,195**	**2,068,175**

Audit fees include the total fees invoiced for the audits of the annual consolidated and non-consolidated financial statements, and the services related to quarterly reports.

Audit-related fees include the total fees invoiced for assurance or related services, such as the audit of the pension plans, services related to public offerings and general advice about accounting standards and the change in accounting framework.

Tax fees include the total fees invoiced for income tax and consumption tax compliance and the various other tax obligations.

All other fees include the total fees invoiced for consulting services, primarily in information technologies.

10.2.3 Interest of Experts

KPMG, Chartered Professional Accountants, acts as the independent external auditors of Énergir Inc. and Énergir, L.P. in accordance with the rules of professional conduct for auditors in Quebec, and consequently signed the auditors' reports on the 2022 Financial Statements of both corporations.

10.2.4 Material Contracts

The following is a list of material contracts entered into by Énergir Inc. and Énergir, L.P. or one of their subsidiaries and in effect as at September 30, 2022:

10.2.4.1 Financial Contracts (Énergir Inc. and Énergir, L.P.)

- On September 22, 2022, Énergir, L.P., as borrower, entered into an agreement with a syndicate of dealers led by BMO Nesbitt Burns Inc. and RBC Capital Markets, whereby, on September 27, 2022, the dealers subscribed for $200.0 million in first mortgage bonds. The bonds yield interest at the annual rate of 4.67% and will mature on September 27, 2032. The bonds are guaranteed by a hypothec on the assets of Énergir, L.P.
- On July 13, 2022, Énergir, L.P. and Énergir Inc. entered into a credit agreement with the Bank of Montreal and a lender's syndicate, as more fully described under Item 6.3 *Financial Management.*
- On February 7, 2022, Énergir L.P., as borrower, entered into an agreement with a syndicate of dealers led by CIBC World Markets and TD Securities Inc. whereby, on February 9, 2022, the dealers subscribed for $325.0 million in first mortgage bonds. The bonds yield interest at the annual rate of 3.04% and will mature on February 9, 2032. The bonds are guaranteed by a hypothec on the assets of Énergir, L.P.
- On April 14, 2020, Énergir Inc., as borrower, and Énergir, L.P., as guarantor, entered into an agreement with a syndicate of dealers led by BMO Nesbitt Burns Inc., National Bank Financial Inc. and Desjardins Securities Inc. whereby, on April 16, 2020, the dealers subscribed for $300.0 million in first mortgage bonds. The bonds yield interest at the annual rate of 2.10% and will mature on April 16, 2027. The bonds are guaranteed by Énergir, L.P. as regards payment of principal and interest, and are secured by collateral security backed by the assets of Énergir Inc. and Énergir, L.P.
- On December 9, 2014, Énergir Inc., as borrower, and Énergir, L.P., as guarantor, entered into a note purchase agreement with investors by way of a private placement. The notes were issued for an aggregate principal amount of US$100.0 million. The notes bear interest at an annual rate of 3.22% and will mature on December 9, 2024. The notes are guaranteed by Énergir, L.P. as regards payment of principal and interest, and are secured by collateral security backed by the assets of Énergir Inc. and Énergir, L.P.
- On February 5, 2013, Énergir Inc., as borrower, and Énergir, L.P., as guarantor, entered into a note purchase agreement with certain investors by way of a private placement. On April 10, 2013, the notes were issued for an aggregate principal amount of US$200.0 million, i.e., two series of US$100.0 million each. The notes bear interest at an annual rate of 4.04% and 4.19%, respectively, and will mature on April 10, 2043 and April 10, 2048, respectively. The notes are guaranteed by Énergir, L.P. as regards payment of principal and interest, and are secured by collateral security backed by the assets of Énergir Inc. and Énergir, L.P.
- On November 11, 2011, Énergir Inc., as borrower, and Énergir, L.P., as guarantor, entered into a note purchase agreement with investors by way of a private placement. On May 15, 2012, the notes were issued for an aggregate principal amount of US$260.0 million, i.e., two series of US$130.0 million each. The notes bear interest at an annual rate of 3.86% and 5.06%, respectively. One matured on May 15, 2022, while the other will mature on May 15, 2042. The notes are guaranteed by Énergir, L.P. as regards payment of principal and interest, and are secured by collateral security backed by the assets of Énergir Inc. and Énergir, L.P.
- On July 15, 1982, Énergir Inc. entered into a trust indenture with La Compagnie de Fiducie, Canada Permanent (replaced by Montreal Trust Company of Canada, to which Computershare Trust Company of Canada succeeded as trustee, effective on June 30, 2000), as trustee, which was amended and restated pursuant to the Trust Deed of Hypothec, Mortgage and Pledge dated August 12, 1991, entered into between Énergir Inc., Montreal Trust Company of Canada, as trustee (to which Computershare Trust Company of Canada succeeded as trustee, effective on June 30, 2000), and Énergir, L.P., as guarantor, as further amended and supplemented by 29 supplemental trust deeds. Such Trust Deed governs the issuance of first mortgage bonds by Énergir Inc. and sets forth the mortgage bondholders' rights. It also provides for the creation of a universal hypothec on all assets of Énergir Inc. in favour of the holders of the first mortgage bonds issued by Énergir Inc.

- On August 12, 1991, Énergir, L.P. entered into a Trust Deed of Hypothec, Mortgage and Pledge with Montreal Trust Company of Canada, as trustee (to which Computershare Trust Company of Canada succeeded as trustee, effective on June 30, 2000), as further amended and supplemented by 36 supplemental trust deeds. Such Trust Deed governs the issuance of the first mortgage bonds by Énergir, L.P. and sets forth the mortgage bondholders' rights. It also provides for the creation of a universal hypothec on all of Énergir, L.P.'s assets in favour of holders of Énergir Inc.'s first mortgage bonds issued under the Trust Deed described in the previous paragraph, the whole as security for Énergir, L.P.'s corporate guarantee pursuant to Énergir Inc.'s Trust Deed.
- On August 12, 1991, Énergir Inc. entered into a trust indenture with General Trust of Canada, as trustee (replaced by National Bank Trust Inc.), as amended by six supplemental trust agreements. This trust agreement governs the issuance of subordinated debentures by Énergir Inc. and sets forth the subordinate debenture holders' rights.

10.2.4.2 Operating Contracts (Énergir, L.P.)

Transportation Contracts with TCLP

- Énergir, L.P. and TCPL have entered into 15 transportation contracts. The first one was signed on September 22, 2003. The contract that first comes to maturity will expire on October 31, 2026, and the last one to come to maturity will expire on October 31, 2040. Under these contracts, TCPL must transport natural gas to Énergir, L.P.'s natural gas distribution system based on TCPL's tolls, as approved or modified from time to time by the CER.
- Énergir, L.P. and TCPL also entered into four transportation service contracts relating to natural gas stored in Ontario. The first one was signed on April 16, 1985. They will expire on October 31, 2026. Under these contracts, TCPL must transport natural gas to Énergir, L.P.'s natural gas distribution system from November 1 to April 15 inclusively of each year, based on TCPL's tolls as approved or modified from time to time by the CER.

Other Contracts with TCPL

- On October 31, 2013, Énergir, L.P. and Ontario's natural gas distributors entered into an agreement in principle with TCPL to ensure access to diversified and affordable sources of natural gas from the Dawn Hub, Ontario. This agreement will expire on December 31, 2030, barring early termination related to external factors. Further to this agreement in principle, Énergir, L.P. and Ontario's natural gas distributors entered into an agreement with TCPL on October 30, 2015 concerning the Energy East and Eastern Mainline projects. This agreement will expire on December 31, 2050, barring early termination related to external factors.

Storage and Transportation Contracts with Enbridge Gas

- Énergir, L.P. and Enbridge Gas entered into three storage contracts. The first one was signed on April 1, 2020. The contract that first comes to maturity will expire on March 31, 2023, and the last one to come to maturity will expire on March 31, 2025. Under these contracts, Enbridge Gas must store natural gas for Énergir, L.P. based on Enbridge Gas's Market Price Service Schedule (or a replacement tariff), depending on the circumstances, as approved or modified from time to time by the Ontario Energy Board.
- Énergir, L.P. and Enbridge Gas entered into eight transportation contracts. The first one was signed on September 2, 2008. The contract that will first come to maturity will expire on March 31, 2024, and the last one to come to maturity will expire on October 31, 2032. Under these contracts, Enbridge Gas must transport natural gas to the system of TCPL (which then transports the natural gas to Énergir, L.P.'s natural gas distribution system) based on Enbridge Gas's Tariff M12 (or a replacement tariff), depending on the circumstances, as approved or modified from time to time by the Ontario Energy Board.

GasEDI Contracts and Other Contracts of a Similar Nature

- Énergir, L.P. entered into GasEDI Base Contracts for short-term sale and purchase of natural gas or contracts of a similar nature with various co-contracting parties. The first of these contracts is dated May 29, 2015. Under these contracts, Énergir, L.P. and these co-contracting parties entered into seven transactions pursuant to which such co-contracting parties shall deliver natural gas to the delivery point specified in the transaction. The first of these transactions is dated November 22, 2017. The first to mature will expire on October 31, 2023 and the last to mature will expire on October 31, 2026.

Storage Contracts with Intragas, Limited Partnership

- On June 20, 2013, Énergir, L.P. and Intragas, Limited Partnership entered into two natural gas storage contracts covering the period from May 1, 2013, to April 30, 2023. The contract is based on Intragas, Limited Partnership's Tariffs E-6 and E-7, as approved or modified from time to time by the Régie.

10.2.4.3 Financing of Wind Farms 2 and 3

- On May 3, 2016, Wind Farms 2 and 3 GP entered into an amended and restated credit agreement for the non-recourse refinancing of Wind Farms 2 and 3 for a total amount of $617.5 million consisting of (i) a $383.4 million term loan maturing in December 2032, (ii) a $192.7 million term loan maturing in December 2029 guaranteed by the Federal Republic of Germany through its export credit agency Euler-Hermes and (iii) a $41.4 million letter of credit facility. The group of lenders consists of Bank of Tokyo-Mitsubishi UFJ, KfW IPEX-Bank, Sumitomo Mitsui Banking Corporation, Mizuho Corporate Bank, AKA Bank, DZ Bank, Laurentian Bank of Canada, Commonwealth Bank of Australia and Crédit Industriel et Commercial.

10.2.4.4 Financial Contracts (Green Mountain)[35]

- On September 23, 2022, Green Mountain entered into a Bond Purchase Agreement with investors. The first mortgage bonds were issued for an aggregate principal amount of US$60.0 million namely, a series for US$25.0 million and a series for US$35.0 million. These bond series yield interest at an annual rate of 5.00% and 4.56%, respectively, and will mature on October 1, 2052 and December 1, 2032, respectively.
- On December 15, 2020, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$60.0 million, namely, a series for US$35.0 million and a series for US$25.0 million. These bond series yield interest at an annual rate of 1.99% and 3.05%, respectively, and will mature on December 15, 2031 and December 30, 2049, respectively.
- On August 18, 2021 Green Mountain entered into a credit agreement with KeyBank National Association and a lending syndicate, as more fully described under Item 6.3 *Financial Management*. The credit agreement has a limit of US$175.0 million and includes an accordion feature of US$25.0 million. The facility matures on August 18, 2024.
- On December 18, 2019, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$40.0 million, namely, a series for US$15.0 million and a series for US$25.0 million. These bond series yield interest at an annual rate of 3.01% and 3.53%, respectively, and will mature on December 18, 2034 and December 18, 2049, respectively.
- On June 13, 2019, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$90.0 million, namely, a series for US$50.0 million and a series for US$40.0 million. These bond series yield interest at an annual rate of 3.79% and 3.95%, respectively, and will mature on June 13, 2034 and June 13, 2039, respectively.
- On September 19, 2018, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$45.0 million, i.e., a series of US$25.0 million and a series of US$20.0 million. These series yield interest at an annual rate of 3.84% and 4.20%, respectively, and will mature on September 19, 2030 and December 3, 2048, respectively.
- On April 26, 2017, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$80.0 million, i.e., a US$65.0 million series and a US$15.0 million series. These series yield interest at an annual rate of 3.45% and 4.17%, respectively, and will mature on June 17, 2029 and April 26, 2047, respectively.
- On December 16, 2015, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$50.0 million, i.e., a US$18.0 million series and a US$32.0 million series. These series yield interest at an annual rate of 3.31% and 4.26%, respectively, and will mature on December 15, 2027 and December 15, 2045, respectively.
- On December 16, 2013, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$75.0 million, i.e., a US$12.0 million series, a US$20.0 million series and a US$43.0 million series. These series yield interest

[35] For the purpose of this Item 10.2.4.4 *Financial Contracts (Green Mountain)* refers either to (i) Green Mountain Power Corporation after the Merger, or (ii) Green Mountain Power Corporation before the Merger or to CVPS, or both.

at an annual rate of 4.07%, 4.39% and 4.89%, respectively, and will mature on January 9, 2029, December 16, 2033, December 16, 2043, respectively.

- On December 6, 2012, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$85.0 million. These series yield interest at an annual rate of 3.99% and will mature on December 1, 2042.
- On October 1, 2012, Green Mountain entered into a 23rd supplemental trust indenture with The Bank of New York Mellon Trust Company, N.A., amending and replacing the trust indenture governing the issuance of the Green Mountain first mortgage bonds bearing the date February 1, 1955. This 23rd supplemental trust indenture has been amended by nine supplemental trust indentures. This Trust Deed governs the issuance of first mortgage bonds by Green Mountain and sets forth the mortgage bondholders' rights. It also provides for the creation of a mortgage on all of Green Mountain's assets in favour of the holders of the first mortgage bonds issued by Green Mountain.
- On September 26, 2012, Green Mountain entered into an agreement with holders of first mortgage bonds issued by CVPS (one of the corporations included in the Merger) to exchange such bonds for bonds issued by Green Mountain and governed by the Green Mountain Trust Indenture described in the previous paragraph.
- On November 16, 2011, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$75.0 million, i.e., a US$50.0 million series and a US$25.0 million series. These series yield interest at an annual rate of 4.56% and 4.61%, respectively, and will mature on November 18, 2041.
- On March 18, 2010, Green Mountain entered into a Bond Purchase Agreement with KeyBanc Capital Markets Inc. and the Vermont Economic Development Authority for the purchase by KeyBanc Capital Markets Inc. of the bonds to be issued by the Vermont Economic Development Authority under the loan and trust agreement described in the following paragraph.
- On March 1, 2010, Green Mountain entered into a Loan and Trust Agreement with the State of Vermont, acting by and through the Vermont Economic Development Authority and The Bank of NY Mellon Company, N.A., acting as trustee, governing the issuance of bonds by the Vermont Economic Development Authority, the proceeds of which were loaned to Green Mountain. The Series B bonds were issued for an amount US$5.0 million. The Series B bonds yield interest at a rate of 6.0% and will mature on April 1, 2035.
- On December 13, 2007, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$16.0 million. They yield interest at an annual rate of 6.17% and will mature on December 1, 2037.
- On July 27, 2006, Green Mountain entered into a Bond Purchase Agreement with investors. These first mortgage bonds were issued for an aggregate principal amount of US$30.0 million. They yield interest at an annual rate of 6.53% and will mature on August 1, 2036.

10.2.4.5 Operating Contracts (Green Mountain)

- On March 2, 2021, Green Mountain entered into a power purchase agreement with Great River Hydro, LLC, as more fully described under Item 4.1.2.1 *Green Mountain*.
- On October 9, 2015, Green Mountain entered into a power purchase agreement with Deerfield Wind, LLC, as more fully described under Item 4.1.2.1 *Green Mountain*.
- On May 24, 2011, Green Mountain entered into a power purchase agreement with NextEra Energy Seabrook, LLC, as more fully described under Item 4.1.2.1 *Green Mountain*, which was amended by an amendment dated January 21, 2015.
- On August 12, 2010, Green Mountain and 17 other utilities in the State of Vermont entered into a long-term power purchase and sale agreement with Hydro-Québec Energy Services (U.S.) Inc., as more fully described under Item 4.1.2.1 *Green Mountain*.
- On December 16, 2009, Green Mountain entered into two long-term supply contracts for the purchase of renewable energy with Granite Reliable Power, LLC, as amended on October 18, 2010 and October 11, 2010, respectively, as more fully described under Item 4.1.2.1 *Green Mountain*.

10.2.5 Complaints or Concerns

The *Policy on the Reporting and Handling of Public and Employee Complaints* states that any person, including employees of Énergir, L.P. and its subsidiaries, wanting to lodge a complaint about the accounting, internal accounting controls or the audit of Énergir, L.P. or to report any violation of the principles set forth in the Code of Ethics may do so, anonymously and at no cost, through the *ClearView Connects* service by one of the following means:

By mail:	ClearView Connects P.O. Box 11017 Toronto, Ontario M1E 1N0
By telephone:	1-844-288-1704
Online at the secure website:	http//www.clearviewconnects.com

ClearView Connects is a service of Syntrio, Inc., a business that offers governance, risk, compliance and human resource solutions as well as anonymous and confidential feedback systems. Their secure feedback systems are designed to protect the identity of those who use the service.

All complaints will be sent to an analytical team consisting, among others, of a representative from each of the following departments: Internal Audit, Corporate Secretariat, Legal Affairs, and Human Resources. This analytical team will examine the complaint. If the complaint pertains to a member of the analytical team, it will be forwarded directly to the Chair of the CGEE Committee.

10.2.6 Risk Factors relating to Énergir Inc. and Énergir, L.P.

Énergir Inc. has developed and applied risk identification, assessment and management practices to mitigate the nature and scope of key risks that could have a material impact on its operations, financial position and consolidated net income.

Additional information regarding Énergir Inc.'s risk factors can be found in section G) *Risk Factors Relating to Énergir Inc. and Énergir, L.P.* on pages 31 to 41 of the 2022 MD&A.

10.2.7 Other Information

Additional information regarding Énergir Inc. is available on the SEDAR website at www.sedar.com under the profile for Énergir Inc.

Additional financial and related information are provided in the 2022 Financial Statements and the 2022 MD&A. The 2022 Financial Statements, the 2022 MD&A and any other public document issued by Énergir Inc. (including the annual information form and any other documents expressly incorporated therein by reference) may be obtained from the Investor Relations Service, 1717 du Havre Street, Montréal, Quebec H2K 2X3, by telephone: (514) 598-3444 ext. 7238 and by email: investors@energir.com or by consulting the SEDAR website at www.sedar.com.

SCHEDULE 10.2.1.1

BOARD OF DIRECTORS

MANDATE [1]

In this mandate, the masculine gender is used solely for the sake of brevity and refers to both women and men.

1. CONSTITUTION AND COMPOSITION

The Board of Directors (the "**Board**") shall be composed of a number of directors set by the Board, upon recommendation of the Corporate Governance, Ethics and Environment Committee, in accordance with the articles of Énergir Inc. (the "**Corporation**"), a majority of whom shall be independent within the meaning of *Regulation 58-101 respecting Disclosure of Corporate Governance Practices* ("**Regulation 58-101**").

The members of the Board must have the relevant qualifications and experience to enable the Board to carry out its responsibilities effectively.

Unless approved by the Board upon the recommendation of the Corporate Governance, Ethics and Environment Committee, a member of the Board shall not receive any compensation from the Corporation or any of its affiliates other than the compensation received as a director or member of a Board committee. Prohibited compensation includes, without limitation, fees paid, directly or indirectly, as a consultant or legal or financial advisor.

The members of the Board are appointed annually by resolution of the sole shareholder in lieu of an annual general meeting of the Corporation.

2. MEETINGS

Regular meetings, four (4) per year, shall be held on such dates, at such times and in such places as the Board may determine. They shall be called by notice given to the members by the Secretary or Assistant Secretary on behalf of the Chair of the Board. Meetings may be held without notice provided the members consent. The presence of a member at the meeting shall constitute consent.

A special meeting may be called at any time by the Chair of the Board, the President and Chief Executive Officer or at the request of any member of the Board.

3. INVITEES

Subject to certain exceptions, the Chief Financial Officer and the Executive Vice-President, Quebec, as well as any other person upon invitation by the Chair of the Board, shall be invited to participate in all or part of the Board's meetings.

4. QUORUM

A quorum at meetings shall consist of a simple majority of the current members of the Board.

5. CHAIR

The Chair of the Board is appointed by the members of the Board upon recommendation of the Corporate Governance, Ethics and Environment Committee. The Chair shall be an independent director within the meaning of Regulation 58-101. He shall preside over the meetings of the Board and ensure the proper conduct of the work arising from its mandate. When the Chair of the Board is unable to attend a meeting, a member of the Board chosen from among the members present may act as Chair of the Board.

6. GENERAL MANDATE

The Corporation's affairs are managed by the directors assembled in a Board, subject to the restrictions in the *Business Corporations Act* (Québec) and the Corporation's By-Laws. However, the Board is not responsible for day-to-day management, which is delegated to the President and Chief Executive Officer and the other officers, but oversees it.

[1] Revision approved by the Board of Directors on December 15, 2022.

Accordingly, the Corporation expects that each director shall:

(a) keep informed and up-to-date about the activities of the enterprise and the industry;

(b) read all of the documentation received for Board meetings and contribute to the decisions made by the Board; and

(c) actively participate in the meetings of the Board, unless prevented from doing so because of incapacity.

To assist it in discharging its responsibilities, the Board has formed the following standing committees, namely the Audit Committee, the Human Resources and Corporate Social Responsibility Committee and the Corporate Governance, Ethics and Environment Committee. The Board has established a mandate for each of the committees it has formed. In addition, the Board has delegated day-to-day management to management by assigning specific responsibilities to the President and Chief Executive Officer.

The Chair of the Board shall ensure that the Board has the human, material and financial resources necessary to carry out its mandate.

7. SPECIFIC RESPONSIBILITIES

The Board's objective is to ensure that the enterprise's resources and its potential are used and developed in such a way as to create value for Noverco Inc., the Corporation's sole shareholder, (the "**Shareholder**") and Énergir, L.P.'s partners. This is to be done in compliance with applicable laws, and the Corporation's values and corporate governance policies and practices. This growth objective includes the protection of the value of the enterprise against the risks it faces. It is also responsible for reviewing and ensuring that Énergir, L.P.'s practices, directions and organizational culture are aligned with its strategic plan.

More specifically, the Board shall, among other things, directly or through its committees:

(a) ensure that management maintains a culture of integrity throughout the organization;

(b) adopt a strategic planning process and periodically approve a strategic plan that addresses business opportunities and risks, among other things;

(c) formulate the Board's expectations of management;

(d) identify and monitor the main risks faced by the business and, in this regard, review biannually the report from management with respect to integrated risk and opportunity management of the business and ensure that there are adequate risk management procedures, measures and systems in place to identify, manage and control of these risks;

(e) plan the succession for senior executives, including hiring, appointments, compensation, evaluation, training and career development;

(f) define responsibilities of the senior executives and their authority to bind the Corporation;

(g) ensure the integrity of the Corporation's internal control and management information systems;

(h) develop the Corporation's approach to corporate governance, including the preparation of a specific set of principles and guidelines, including for recruiting and renewing directors;

(i) approve and monitor the Corporation's *Policy respecting disclosure of information*;

(j) on the recommendation of the relevant Committee, adopt and revise any other corporate policy it considers appropriate and ensure it is followed;

(k) establish measures for receiving reactions and comments from interested parties (including holders of the Corporation's and Énergir, L.P.'s securities);

(l) identify decisions that require the pre-approval of the Board and establish approval and authorization policies for decisions and contracts binding the Corporation;

(m) on the recommendation of the Corporate Governance, Ethics and Environment Committee and in compliance with Énergir's *Policy Regarding Diversity on the Board of Directors*, fill any vacancy in a Board directorship until the next annual meeting of the Shareholder, and review candidates proposed by the Shareholder;

(n) prepare and adopt a Code of Conduct and Ethics for the directors and officers of the Corporation and the employees of Énergir, L.P. and those of its Canadian subsidiaries, ensure it is updated regularly and followed, including monitoring and approval of all exemptions, where applicable;

(o) periodically evaluate the effectiveness of the Board, its members, its Chairman, its committees and their members and chairmen and, based on the report of the Corporate Governance, Ethics and Environment Committee, give particular consideration to:

   i. the size of the Board;

   ii. the competencies and skills the Board as a whole should possess;

iii. the performance of the Board and its members;

iv. the impact of the individual personalities and qualities of each director on the Board dynamic;

v. the individual competencies and skills of each director;

vi. the means likely to improve the performance of the Board and each of its members in the future;

vii. the cooperation received from management;

viii. the mandates and operating mode of the Board and its committees, making any necessary adjustments; and

ix. Énergir's *Policy Regarding Diversity on the Board of Directors*, including the objectives set forth by the Corporation regarding diversity on the Board;

(p) receive the report of the Corporate Governance, Ethics and Environment Committee regarding diversity on the Board and the report of the Human Resources and Corporate Social Responsibility Committee regarding diversity within the Corporation's management, review and assess this representation and the impact of steps taken in order to achieve its objectives and, if needed, set forth new measures or adjustments to existent measures;

(q) prepare a job and function description for the President and Chief Executive Officer, which shall define the responsibilities of management;

(r) ensure all directors:

i. all relevant information when they are appointed to the Board concerning the role of the Board and its committees as well as the expectations with respect to their individual contribution, which information is contained in the director's online site; and

ii. understand the nature of the activities of the Corporation and Énergir, L.P. and how they are managed;

(s) provide opportunities and means for ongoing education for all directors so that each of them can develop his/her competencies and skills as a director and have an up-to-date knowledge and understanding of the affairs of the Corporation and Énergir, L.P.;

(t) with the assistance of the Corporate Governance, Ethics and Environment Committee, create committees of the Board, establish their mandate and appoint their members;

(u) with the assistance of the Corporate Governance, Ethics and Environment Committee, appoint the Chair of the Board and the Chair of each committee of the Board, and approuve the amount of their compensation and that of the directors;

(v) on the recommendation of the Human Resources and Corporate Social Responsibility Committee, establish and approve the compensation policies and programs for senior management, evaluate the performance of the President and Chief Executive Officer based on the objectives set, and establish his compensation;

(w) with the assistance of the Audit Committee, ensure compliance with accounting standards, as well as the integrity and adequacy of financial reporting;

(x) on the recommendation of the Audit Committee, approve the interim and annual financial statements of the Corporation and the annual financial statements of Énergir, L.P.;

(y) determine the appropriateness of declaring, and declare, where applicable, the payment of dividends to the Shareholder, a reduction of the capital of the Corporation as well as the distribution of Énergir, L.P.'s income to the partners;

(z) on the recommendation of the Audit Committee, recommend the choice of the external auditors to the Shareholder;

(aa) on the recommendation of the Audit Committee, approve the interim and annual Management's Discussion and Analysis and the Annual Information Forms of the Corporation;

(ab) on the recommendation of the Human Resources and Corporate Social Responsibility Committee, approve the Report on Executive Compensation in the Corporation's Annual Information Form;

(ac) on the recommendation of the Corporate Governance, Ethics and Environment Committee, approve the governance and environmental disclosure in the Corporation's Annual Information Form;

(ad) approve the charters, by-laws and administrative resolutions as well as any amendments to these documents;

(ae) approve important regulatory matters;

(af) approve operating and capital budgets of the Corporation and Énergir, L.P.;

(ag) approve and monitor important budgets and projects of the Corporation, Énergir, L.P. or a subsidiary, for a major (in terms of dollars or strategic nature) acquisition or investment;

(ah) approve the acquisition or sale of major assets and any other important transaction involving the Corporation, its share capital, its property, its rights or its obligations;

(ai) approve any major reorganization or downsizing;

(aj) approve the issue, purchase or redemption of the securities of the Corporation and Énergir, L.P. and approve the related reporting process;

(ak) approve the form and content of the certificates evidencing the securities of the Corporation and Énergir, L.P; and

(al) in collaboration and on the recommendation of the applicable committees, (i) ensure that environmental, social and governance ("**ESG**") factors are incorporated into the long-term strategic objectives of Énergir, L.P. and monitor ESG initiatives and integration across Énergir, L.P., and (ii) approve Énergir, L.P.'s *ESG Policy* and *Environmental Policy*, as well as the Corporation's published report on climate change.

8. BOARD PERFORMANCE ASSESSMENT AND WORK PLAN

The Board:

(a) shall evaluate and review its performance in collaboration with the Corporate Governance, Ethics and Environment Committee;

(b) every two (2) years, shall review and revise the adequacy of its mandate in collaboration with the Corporate Governance, Ethics and Environment Committee; and

(c) shall prepare an annual work plan to be reviewed during the year as required.

9. ROLE OF THE CHAIR OF THE BOARD

The Chair of the Board shall be responsible in particular for managing the affairs of the Board and monitoring its effectiveness, setting the agenda for Board meetings and relations with the Corporate Secretary with respect to the affairs of the Board and its Committees. He shall also ensure that any important strategic matters or issues are communicated to the Board for approval and that the Board receives the information, reports, documents and opinions required so that the members of the Board can fulfil their role. He shall ensure the decisions made by the Board are implemented. The Chair of the Board shall ensure all interested parties are informed about the Board’s policies with respect to compliance with the by-laws and the *Code of Ethics* of the Corporation. He shall also make himself available to advise the President and Chief Executive Officer.

Specific responsibilities of the Chair of the Board shall be:

(a) to ensure harmonious relations between the Shareholder, the Board and management;

(b) to ensure that the directors hold regularly scheduled meetings at which members of management are not in attendance;

(c) to inform the Shareholder of the recommendations for new directors based on the report of the Corporate Governance, Ethics and Environment Committee;

(d) to propose the composition of the Board Committees to the Corporate Governance, Ethics and Environment Committee;

(e) to ensure that the Board Committees have the human, material and financial resources required to carry out their mandate;

(f) to sit ex-officio as a member on the Human Resources and Corporate Social Responsibility Committee;

(g) at his discretion, to be able to sit as an invitee or member on other Board Committees;

(h) to inform management about his evaluation of the information provided to the directors; and

(i) to ensure, with the Corporate Governance, Ethics and Environment Committee, that the best corporate governance practices are followed.

10. COMMITTEE CHAIRS

Each committee Chair shall ensure that the committee fulfills its mandate and shall, in collaboration with the Corporate Secretary:

(a) ensure that the affairs of the committee are properly managed and monitor its effectiveness;

(b) set the agenda for the meetings of the committee;

(c) ensure that all matters and issues of strategic importance relating to this committee are communicated to the Board as soon as possible;

(d) ensure that the Board receives the information and recommendations it requires from the committee to properly discharge its duties; and

(e) present, at least once a year, a report on the committee’s work in fulfilling its mandate and adhering to its annual plan.

The Chair of the Corporate Governance, Ethics and Environment Committee shall also make himself available to address the concerns of any employee of Énergir, L.P. or other persons with respect to questionable accouting, internal control, auditing or information technology matters, including cybersecurity.

If the Chair of a committee does not attend a meeting of the committee, the committee shall choose one of the other members present at the time to chair the meeting.

11. CORPORATE SECRETARY

The Board and the President and Chief Executive Officer have given the Corporate Secretary the responsibility for organizing all meetings of the Board and its committees. He shall also:

(a) prepare information provided by management and distribute it to the directors in a form that will facilitate an understanding thereof and decision-making;

(b) ensure a follow-up of Board and committee decisions;

(c) ensure a corporate file is maintained;

(d) advise directors as to procedures and responsibilities, in particular with respect to corporate governance;

(e) keep corporate by-laws and policies of the Corporation up-to-date; and

(f) provide directors with the necessary information about the enterprise so they can discharge their responsibilities with prudence and diligence.

12. IN CAMERA SESSIONS

At the end of each meeting, the Board shall deliberate without management. The Chair of the Board shall chair the in camera session.

AUDIT COMMITTEE

MANDATE [1]

In this mandate, the masculine gender is used solely for the sake of brevity and refers to both women and men.

1. CONSTITUTION AND COMPOSITION

To assist it in discharging its oversight responsibilities for accounting processes, information technologies and financial reporting, internal control systems, financial management and the management of risks, the Board of Directors of Energir Inc. (the "**Board**") formed an Audit Committee (the "**Committee**") to which it appoints the members and the Chair.

The Committee shall be composed of a minimum of three (3) directors, each of whom must be financially literate within the meaning of the applicable securities laws and regulations, i.e. as a minimum be capable of reading and understanding the financial statements of the Corporation.[2] The Committee shall be composed of independent directors within the meaning of *Regulation 52-110 respecting Audit Committees* (“**Regulation 52-110**”) of the Canadian Securities Administrators (“**CSA**”), subject to the independence exemptions provided therein.

Unless approved by the Board is received upon recommendation of the Corporate Governance, Ethics and Environment Committee, a member of the Committee shall not receive any compensation from the Corporation or any of its affiliates other than the compensation received as a director or member of a Board committee. Prohibited compensation includes, without limitation, fees paid, directly or indirectly, as a consultant or legal or financial advisor.

The members of the Committee shall be appointed annually by the Board upon recommendation of the Corporate Governance, Ethics and Environment Committee. The term of office of a member of the Committee shall automatically terminate if they cease to be independent as determined by the Board, subject to having availed themselves of an independence exemption provided for in Regulation 52-110, if applicable.

2. MEETINGS

Regular meetings, four (4) per year, shall be held on such dates, at such times and in such places as the Board may determine. Meetings shall be called by notice given to members by the Secretary or Assistant Secretary on behalf of the Chair of the Committee. Meetings may be held without notice provided the members consent. The presence of a member at the meeting shall constitute consent.

A special meeting may be called at any time by the Chair of the Committee, the Chair of the Board, the President and Chief Executive Officer of the Corporation or at the request of any member of the Committee.

In addition, the Chair of the Committee shall call a meeting of the Committee when requested by the external auditor (the "**External Auditor**") or the chief internal auditor (the "**Internal Auditor**").

3. INVITEES

Other members of the Board may be invited to attend meetings of the Committee on a regular or occasional basis without being a member of the Committee or having voting rights.

The Chair of the Board, if not a member of the Committee, may participate in any meeting. Subject to certain exceptions, the Chief Financial Officer, the Corporate Controller, the Assistant Corporate Controller, the Treasurer, the representative(s) of the External Auditor and the Internal Auditor, as well as any other person upon invitation by the Chair of the Committee or a member of the Committee, shall be invited to participate in all or part of its meetings.

4. QUORUM

A quorum at meetings shall consist of a simple majority of the current members of the Committee.

[1] Revision approved by the Board of Directors on December 15, 2022.
[2] For the purposes of this mandate, "Corporation" refers to Énergir Inc. and/or Énergir, L.P., depending on the context.

5. CHAIR

The Chair of the Committee is appointed by the Board upon recommendation of the Corporate Governance, Ethics and Environment Committee. The Chair shall preside over Committee meetings and ensure the proper conduct of the work arising from its mandate. When the Committee Chair is unable to attend a meeting, a member of the Committee chosen from among the members then present may act as Chair of the Committee.

6. GENERAL MANDATE

The Committee's mandate is to provide assurance to the Board that the Corporation has an adequate and rigorous financial and information technology control framework. It is responsible for overseeing the financial reporting process, the reporting of this information and the relationship with the External Auditor and the Internal Auditor. It has direct communication channels with the External Auditor and the Internal Auditor at all times. It also ensures the effectiveness of internal controls and compliance with laws and regulations and with the accounting principles, standards and rules applicable to the Corporation. It ensures that the Corporation's management protects the Corporation's assets through appropriate risk management. Finally, it reviews the performance, independence and compensation of the External Auditor and ensures an approval process for non-audit services provided by the External Auditor.

Under this mandate, the Committee may delegate certain authority to one or more of its members, including the authority to pre-approve external non-audit services to be provided by the External Auditor, provided such approval is submitted to the Committee at its first regular meeting after the approval has been given.

The Chair of the Board shall ensure that the Committee has the human, material and financial resources necessary to carry out its mandate. If it deems it necessary, the Committee has the power to hire any outside advisor it deems necessary to carry out its duties and to set and pay his compensation.

7. SPECIFIC RESPONSIBILITIES

The Committee’s specific responsibilities shall include the following:

Risk Management

(a) reviewing from time to time reports from management of the Corporation with respect to the identification and analysis of the financial risks and the risks related to information technologies, including cybersecurity, that may affect the Corporation, and ensuring that there are adequate risk management procedures, measures and systems in place to identify, manage and control these risks;

(b) support the Board in its review of the biannual report from management of the Corporation with respect to integrated risk and opportunity management of the business and ensuring that there are adequate risk management procedures, measures and systems in place identify, manage and control these risks;

(c) reviewing each quarter a report on the tax issues and the related follow-up being done and reviewing major disputes with tax authorities;

(d) reviewing each quarter the report on disputes, claims, notices of assessment or regulatory non-compliance, and threats to the Corporation’s operations and the related follow-up being done and reviewing the material disputes or potential material disputes with third parties, and assessing the appropriateness of their disclosure in the documents reviewed by the Committee;

(e) reviewing annually or when circumstances require, the insurance coverage;

(f) requesting a special audit if required;

Information Technology, Operational Technology and Resilience

(a) reviewing each quarter the report on information technology projects and priorities, cybersecurity, the physical security of the facilities and the follow-up being done;

(b) reviewing from time to time the report on the Corporation’s compliance with respect to personal information to ensure that its practices comply with industry standards and the standards imposed by the applicable laws and regulations;

(c) reviewing and monitoring the actions, targets and performance indicators of the governance objective related to physical and digital robustness and resilience included in or identified by the Corporation's ESG plan;

(d) reviewing annually the results of the various penetration tests relating to the physical security of the facilities and the resilience of the Corporation;

(e) reviewing from time to time the Corporation’s emergency and resilience plans;

Internal Audit

(a) reviewing and approving the mandate and annual audit plan of the Internal Auditor;

(b) reviewing each quarter with the External Auditor and the Internal Auditor the internal audit activities report, and the follow-up of the management of the Corporation with respect thereto and reviewing with the Internal Auditor the difficulties encountered in connection with his mandate;

(c) reviewing from time to time the effectiveness of the Internal Audit function, including its compliance with the standards of the Institute of Internal Auditors;

(d) reviewing from time to time the performance and level of independence of the Internal Auditor and advising the President and Chief Executive Officer of the results of this evaluation;

(e) providing its opinion on his appointment or revocation;

External Audit

(a) recommending the appointment of the External Auditor for the Corporation to the Board, it being understood that the appointment of the External Auditor must ultimately be approved by the shareholder of Énergir Inc., on its own behalf and acting in its capacity as general partner of Énergir, L.P.;

(b) recommending to the Board, the compensation to be paid to the External Auditor for his services;

(c) overseeing the work of the External Auditor whose services are retained to prepare or issue an audit report or to render other audit, review or attestation services to the Corporation, including the resolution of disagreements between the management of the Corporation and the External Auditor concerning the financial information;

(d) pre-approving all non-audit services that the External Auditor shall provide to the Corporation;

(e) evaluating at least once a year the competence and the quality of the services of the External Auditor. The External Auditor shall report directly to the Committee;

(f) ensuring the External Auditor is a participating audit firm within the meaning of the *Regulation 52108 respecting Auditor Oversight* of the CSA and that it complies, where applicable, with any directive or restriction issued by the *Canadian Public Accountability Board;*

(g) reviewing the public reports and information bulletins of the *Canadian Public Accountability Board* published for audit committees and received from the External Auditors, along with any significant findings arising from the inspection of the Corporation's audit file;

(h) at least once a year, reviewing the written report prepared by the External Auditor describing:

  i. any significant issues concerning the audit file of the Corporation arising during any peer controls or reviews, information requests, or inquiries carried out by a government, regulatory or professional authority, as well as any steps taken in this regard; and

  ii. internal quality-control procedures implemented by the External Auditor, including any significant issues raised during the latest internal review thereof, as well as any steps taken in this regard;

(i) at least once a year, evaluating and ensuring independence of the External Auditor, and to that end, it shall:

  i. review the existing or proposed relationships between the Corporation, its personnel or its consultants and the partners, employees, former partners and former employees of the External Auditor;

  ii. review and approve the Corporation's hiring policy with respect to partners, employees, former partners and former employees of the present and former External Auditor of the Corporation, namely, the *Policy on hiring partners and employees of the external auditors*, and ensure it is complied with; and

  iii. ensure that the *Policy and Procedure Regarding Pre-approval of External Audit and Non-Audit Related Services* is complied with;

(j) ensuring there is a rotation of the engagement partner, the reference partner and other audit partners within the standards prescribed by the regulatory authorities and the applicable securities and governance laws and regulations;

(k) reviewing and approving the annual audit plan of the External Auditor and related budget proposed by the External Auditor as well as any change thereto;

(l) reviewing the scope of the audit, the External Auditor's reports following his interim reviews and annual audits, the External Auditor's letter addressed to the management of the Corporation and related comments therefrom and the follow-up done by the management of the Corporation;

(m) reviewing any problems encountered by the External Auditor in the course of his engagement, in particular any restrictions that may have been imposed by the Corporation's management;

(n) reviewing the External Auditor's recommendation letter with respect to internal controls, the responses thereto from management of the Corporation and the steps taken by management of the Corporation to address them;

(o) from time to time questioning the External Auditor about the competence and performance of the Corporation's personnel responsible for finance, accounting and internal controls;

Financial Information

(a) monitoring the integrity and quality of the internal control systems, the financial reporting process and accounting policies through investigations and discussions with the Corporation’s management, the Internal Auditor and the External Auditor;

(b) reviewing the financial forecasts communicated by the management of the Corporation to the Board and ensuring that adequate controls and procedures are established and maintained by the management of the Corporation to ensure the integrity of these financial forecasts;

(c) reviewing with the management of the Corporation and the External Auditor (i) the quality, relevance and disclosure of the accounting principles and policies used and the underlying assumptions and financial reporting practices and (ii) the impact of any proposed changes to these or securities regulations relating to accounting policies and financial reporting;

(d) ensuring the financial information complies with the applicable securities laws, regulations and policies;

(e) reviewing and approving the interim financial statements of Énergir, L.P., and also reviewing the annual financial statements of Énergir, L.P. which include the External Auditor’s Report, and recommending the approval thereof by the Board;

(f) reviewing, prior to public release, the annual information forms, prospectuses, interim and annual financial statements and Management’s Discussion and Analysis of Énergir Inc. (including the Corporation's risks and opportunities therein) and recommending the approval thereof by the Board;

(g) ensuring there are adequate procedures for reviewing public disclosures of financial information extracted or derived from the Corporation’s financial statements and from time to time assessing the adequacy of these procedures;

(h) reviewing the Declaration of the Chief Financial Officer regarding the quarterly income distribution and the quarterly dividend and making recommendations to the Board with respect thereto;

(i) reviewing all non-routine correspondence with the regulatory authorities, and any complaint involving a regulatory authority or published information that raises issues with respect to the financial statements, the financial information or the accounting policies;

(j) in collaboration with the Corporate Governance, Ethics and Environment Committee, reviewing the corporate policies, in particular with respect to financial reporting and, if it deems appropriate, those concerning information technology, and ensuring their follow-up;

(k) receiving each quarter an executive summary of the minutes of the Audit Committees of the Canadian and U.S. subsidiaries, if applicable;

Certifications and Compliance Reports

(a) ensuring the certifications of the President and Chief Executive Officer and the Vice President and Chief Financial Officer of the Corporation are provided on a timely basis and reviewing them following receipt;

(b) receiving from Corporate Control a report on compliance with the financial reporting laws and regulations as well as with the laws and regulations applicable to securities;

Committee Performance Assessment and Work Plan

(a) evaluating and reviewing its performance in collaboration with the Corporate Governance, Ethics and Environment Committee and reporting thereon to the Board. If necessary, preparing and following up on an action plan to address the assessment results;

(b) every two (2) years, reviewing and revising the adequacy of its mandate in collaboration with the Corporate Governance, Ethics and Environment Committee and making its recommendations to the Board; and

(c) preparing an annual work plan to be revised during the year as required.

8. OTHER MANDATES

The Committee shall carry out such other duties as may be assigned to it by the Board.

9. REPORTING

The Committee shall report to the Board at the Board meeting following its own meeting. The Chair of the Committee shall report verbally on items that are of immediate interest to the Board and submit the Committee's recommendations for approval by the Board. The Chair of the Committee shall also present, at least once a year, a report on the Committee's work in fulfilling its mandate and adhering to its annual work plan.

10. IN CAMERA SESSIONS

The Committee shall hold a number of in camera sessions during each meeting, with the External and Internal Auditors, as well as with and without the management of the Corporation.

Fortis Investor Presentation, Q1, 2023

FORTIS

INVESTOR PRESENTATION

Q1 2023

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in this presentation within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2023-2027, including cleaner energy investments; annual dividend growth guidance through 2027; forecast rate base and rate base growth for 2023 through 2027; the 2030 GHG emissions reduction target; the 2035 GHG emissions reduction target and the projected asset mix; the 2050 net-zero GHG emissions target; TEP's Integrated Resource Plan; planned coal retirements and the expectation to exit coal by 2032; the nature, timing, benefits and expected costs of certain capital projects, including Wataynikaneyap Transmission Power Project, ITC's transmission projects associated with the MISO Long-Range Transmission Plan, FortisBC Tilbury LNG Storage Expansion, FortisBC Tilbury 1B Project, FortisBC Eagle Mountain Woodfibre Gas Line Project, FortisBC AMI Project, FortisBC Okanagan Capacity Upgrade, UNS renewable energy and storage projects, UNS Vail-to-Tortolita Transmission Project, and additional opportunities beyond the capital plan, including investments related to the Inflation Reduction Act, the MISO Long-Range Transmission Plan, climate adaptation and grid resiliency, and renewable fuel solutions and LNG infrastructure in British Columbia; expected sources of funding for the 2023-2027 capital plan; expected capital structure stability through 2027; the expectation that the long-term dividend guidance will provide flexibility to fund more capital internally; forecast credit metrics through 2027; the expectation of minimal impacts from the introduction of an alternative minimum income tax; the expected timing, outcome and impact of regulatory proceedings and decisions; the expectation that there will be no significant change in UNS' 2023 pension expense; and forecast debt maturities for 2023-2032.

Forward looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: no material impact from volatility in energy prices, the global supply chain and persistent inflation; assumed moderating inflation levels with return to historical averages in 2025; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project or financing cost overrun; no material changes in the assumed U.S. dollar to Canadian dollar exchange rate; sufficient human resources to deliver service and execute the capital plan; no significant variability in interest rates; and the Board exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully, and undue reliance should not be placed on the forward-looking information. For additional information with respect to certain of these risks or factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information herein is given as of the date of this presentation. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Unless otherwise specified, all financial information is in Canadian dollars and rate base refers to midyear rate base.

A PREMIUM ENERGY DELIVERY BUSINESS

93% Transmission & Distribution Assets

FORTIS

HIGH QUALITY PORTFOLIO

10 Regulated Utility Businesses

3.4M Electric & Gas Customers

9,200 Employees

99% Regulated Utility Assets

~$26B Market Capitalization(1)

~9% Average Annual 10-Year Total Shareholder Return(1)

$36B 2023F Rate Base

(1) As of January 31, 2023.

OUR VISION & STRATEGY

A PREMIUM NORTH AMERICAN UTILITY DELIVERING A CLEAN ENERGY FUTURE


Operational Excellence


Financial Strength

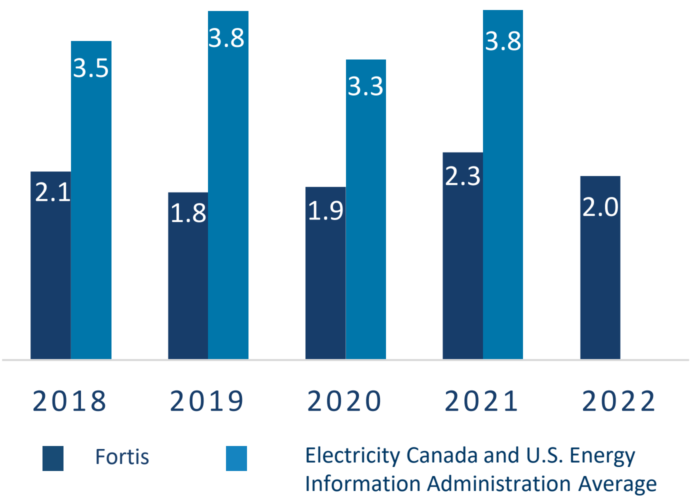

Diversified Regulated Portfolio


Substantially Autonomous Business Model

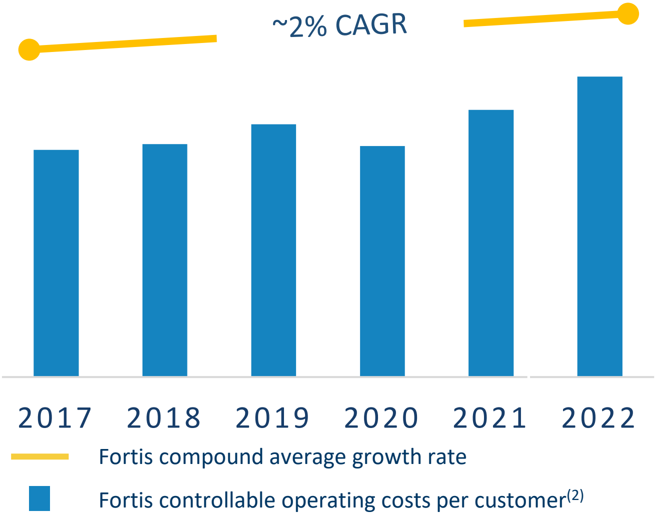

Strong Governance

DELIVERING SAFE AND RELIABLE SERVICE

Average Electricity Customer Outage Duration (Hours)(1)



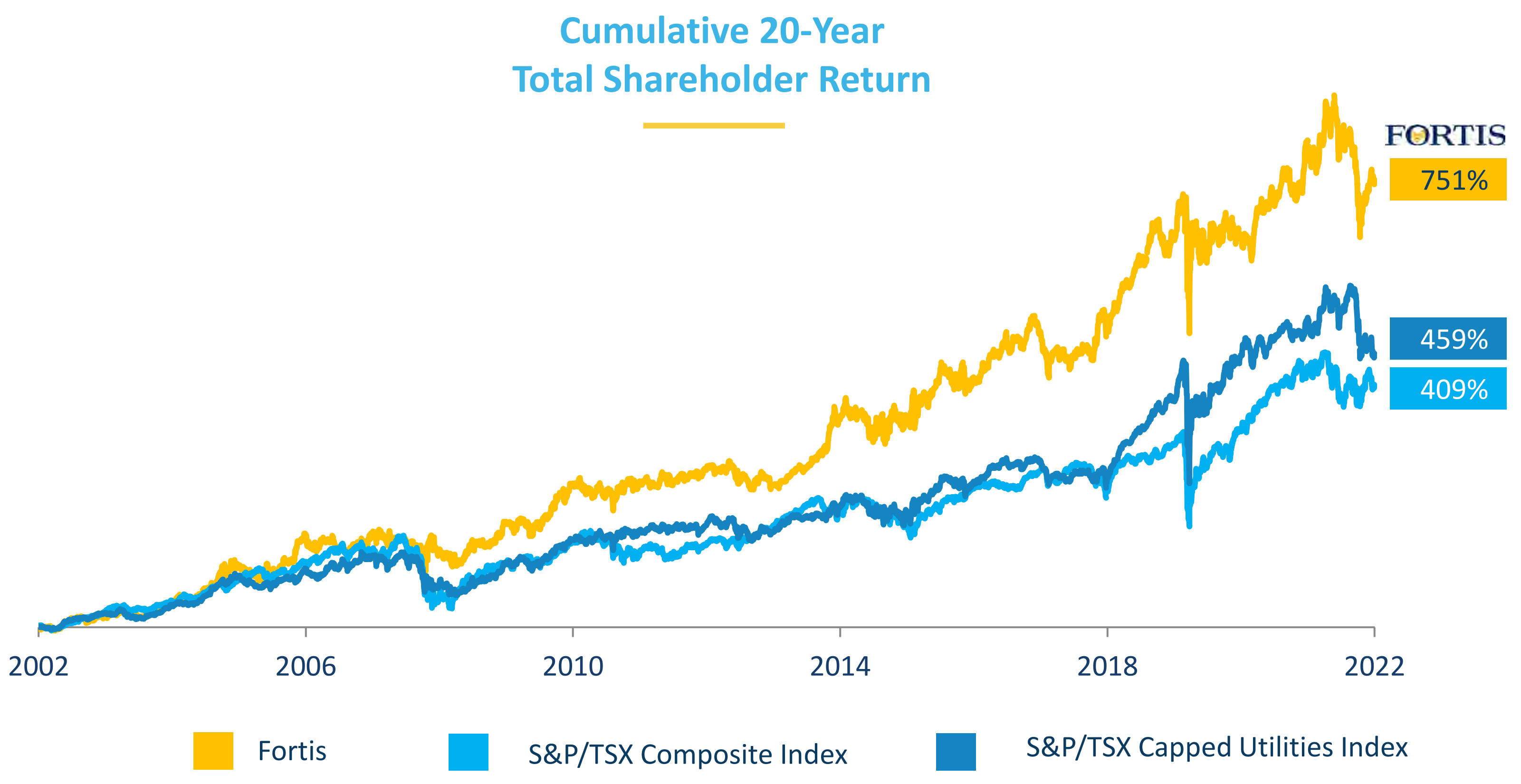
Managing Controllable Operating Costs Below Inflation



(1) Based on weighted average of Fortis' customer count in each jurisdiction. 2022 industry data not yet available.
(2) Controllable operating cost per customer is a financial measure used by management to evaluate operating efficiency. May not be comparable with measures used by other entities and excludes costs that are considered largely outside of management's control (e.g., purchased power, generation fuel expense).

FORTIS

20-YEAR TOTAL SHAREHOLDER RETURN



Average Annual Total Shareholder Returns

1-Year	(7.9%)
5-Year	7.2%
10-Year	8.7%
20-Year	11.3%

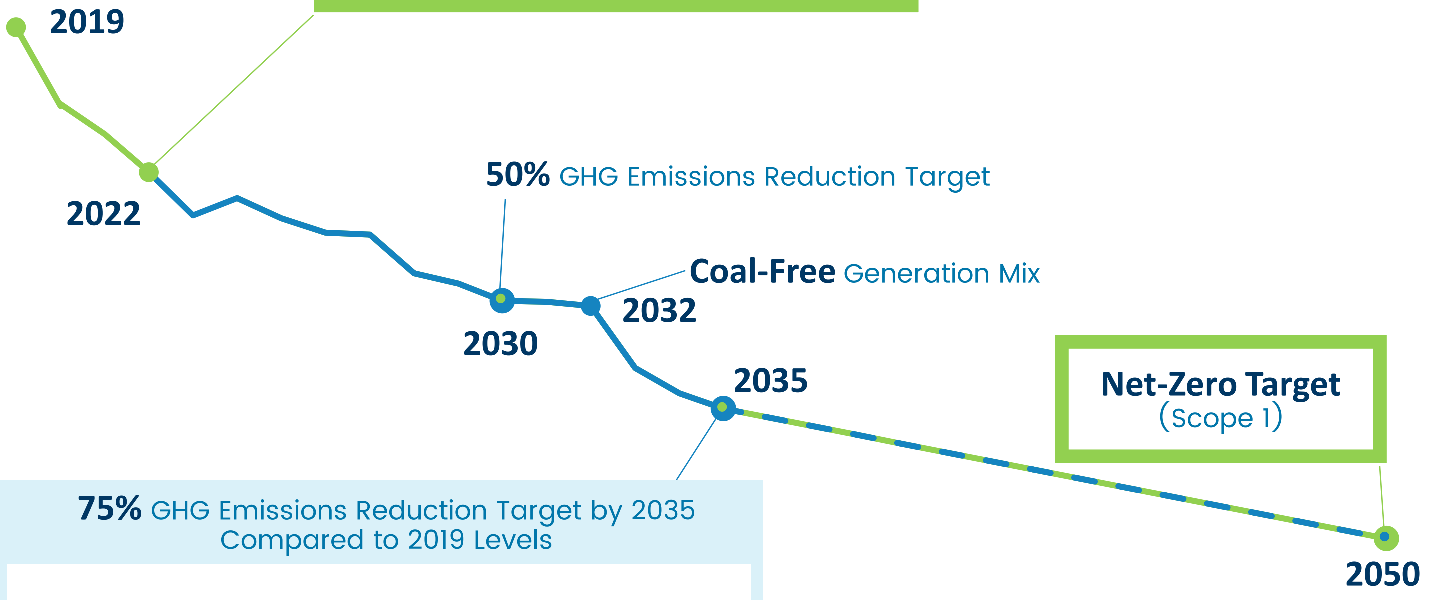
Note: Cumulative 20-year total shareholder return as at December 31, 2022.

CARBON EMISSIONS REDUCTION ON TRACK

2022 Sustainability Highlights:

- Released first TCFD and Climate Report
- Fortis aligned with GRI and SASB
- Strong board diversity with 54% female directors and 2 directors identifying as visible minorities
- New sustainability-linked loan provisions
- Enhanced linkage between sustainability performance and executive compensation

Achieved 28%
GHG Emissions Reduction Since 2019



75% GHG Emissions Reduction Target by 2035 Compared to 2019 Levels

ADDING CLEAN GENERATION

3,400 MW Planned Additions of Wind, Solar and Storage through 2035

PLANNED COAL RETIREMENTS

2022	2027	2031	2032
-170 MW	**-387 MW**	**-110 MW**	**-406 MW**
San Juan ✓	Springerville Unit #1	Four Corners	Springerville Unit #2

Actual GHG Emissions Reduction
Forecast GHG Emissions Reduction as of January 2023
Illustrative Emissions Reduction

ESG LEADERSHIP

Environmental

- 2050 net-zero direct emissions goal, with interim targets to reduce GHG emissions 50% by 2030 and 75% by 2035
- Progress: More than halfway to achieving our 50% by 2030 target with a 28% reduction in Scope 1 emissions relative to 2019 levels
- 170 MW of coal generation capacity was retired at TEP in June 2022: expect to be coal-free by 2032
- 15% increase in renewable electricity generation capacity since 2019: TEP plans to add 3,400 MW of wind, solar and storage through 2035
- Five-year capital plan includes $5.9B for cleaner energy investments
- FortisBC experienced its largest annual increase in renewable gas supply in recent years and has signed more than 30 RNG supply agreements
- In 2022, FortisBC announced a partnership for a new pilot project that will use an innovative technology for the first time in North America to produce zero-carbon hydrogen from natural gas

Social

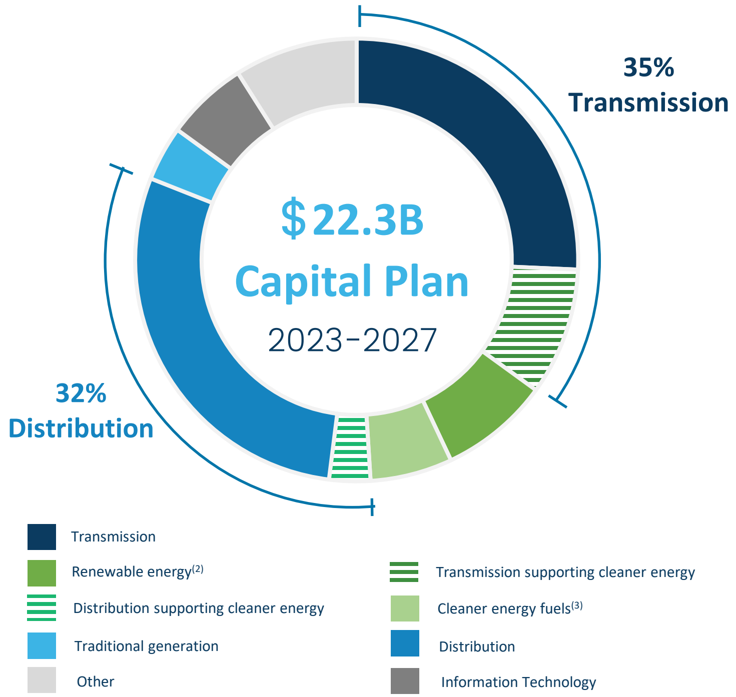
- Focus on Indigenous partnerships and business
- 1,800 KM Wataynikaneyap transmission line connecting 17 remote First Nations communities to the Ontario power grid is 73% complete at the end of 2022; expected to be completed in 2024
- Focus on just transition
- ~$10M of community investment in 2022

Governance

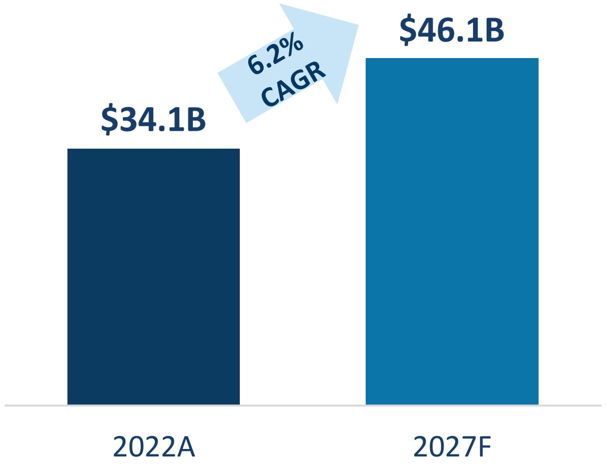
- Independent chair; 12 of 13 directors are independent
- 54% of Fortis board members are female; 2 identify as a visible minority at the end of 2022
- Average board tenure of 4.9 years
- 73% of Fortis utilities have a female in the position of CEO or board chair
- Executive compensation linked to climate and diversity targets

$22.3B FIVE-YEAR CAPITAL PLAN

$5.9B Cleaner Energy Investments(1)



Capital Plan Supports Low-Risk Rate Base Growth



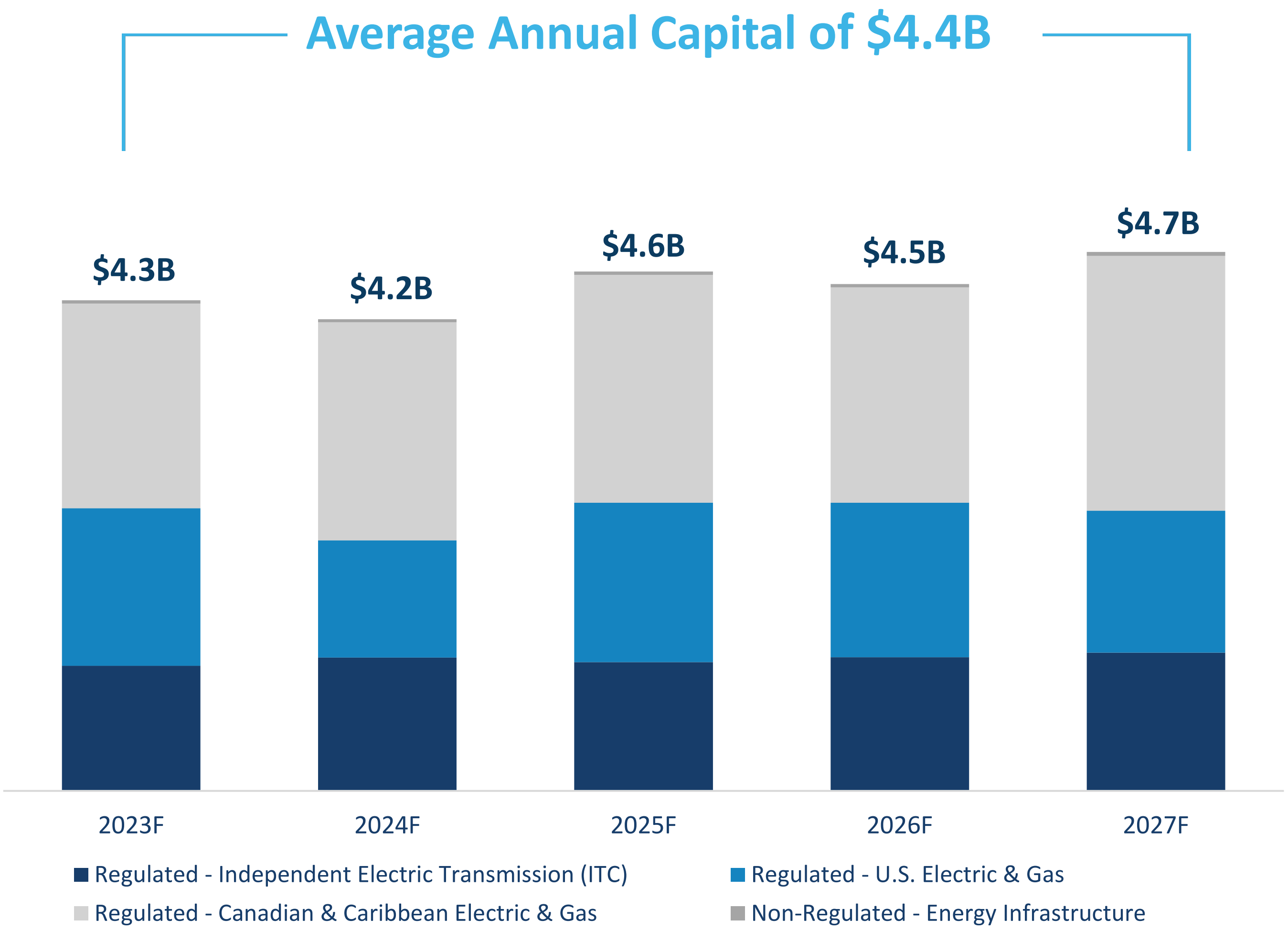
Continued Focus on Customer Affordability

- Targeting controllable operating cost increases below inflation, consistent with historical practice
- Focused on preventative maintenance and innovation to reduce operating costs
- Cleaner energy investments with fuel savings for customers
- Energy efficiency programs

Note: The Capital Plan is a forward-looking Non-U.S. GAAP financial measure calculated in same the manner as Capital Expenditures. Refer to 2022 MD&A for the Non-U.S. GAAP reconciliation. U.S. dollar-denominated capital expenditures and rate base converted at a forecast USD:CAD foreign exchange rate of 1.30.

(1) Direct cleaner energy investments defined as capital that supports reductions in air emissions, water usage and/or increases customer energy efficiency.
(2) Includes clean generation and energy storage.
(3) Includes renewable natural gas and liquefied natural gas.

FIVE-YEAR PLAN AT A GLANCE



Note: The Capital Plan is a forward-looking Non-U.S. GAAP financial measure calculated in the same manner as Capital Expenditures. Refer to 2022 MD&A for the Non-U.S. GAAP reconciliation. U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30 for 2023-2027.

Highly Executable Capital Plan

- 83% Smaller Projects
- 17% Major Projects

- 55% U.S.
- 41% Canada
- 4% Caribbean

- 99% Regulated

CAPITAL PLAN CONCENTRATED AT THREE LARGEST UTILITIES

ITC
A FORTIS COMPANY

- Infrastructure investments including reliability and resiliency upgrades, increased capacity, etc.
- ~US$0.7B included in plan for MISO Long-Range Transmission Plan (LRTP). Estimated transmission investments of US$1.4-$1.8B through 2030 associated with six of 18 LRTP projects
- Economic development, load and changes in generation interconnections
- Grid security investments

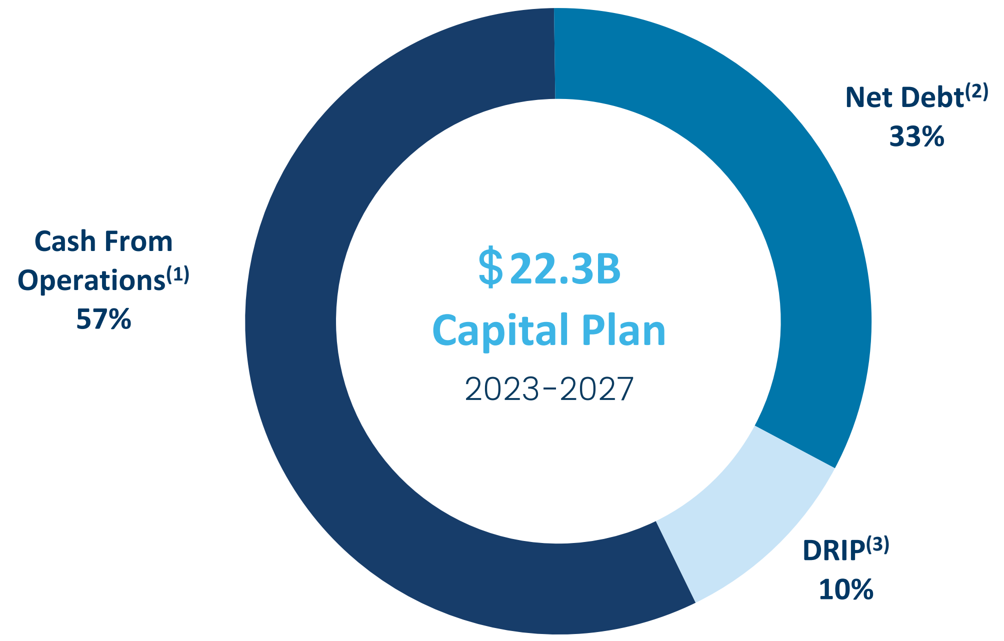
FORTIS BC

- Reliability and integrity investments
- Natural gas infrastructure including LNG resiliency tank, Tilbury 1B and Eagle Mountain Woodfibre gas line projects
- Automated Gas Metering Infrastructure and Okanagan Capacity Upgrade
- Renewable gas projects and natural gas for transportation

UNS
UNS Energy Corporation
A Fortis Company

- Includes ~$1.2B of renewable and storage investments to transition to cleaner energy aligned with TEP's Integrated Resource Plan (IRP)
- Distribution investments including customer meter infrastructure and grid resiliency and modernization
- Vail-to-Tortolita Transmission Project ($378M)

NO DISCRETE EQUITY REQUIRED TO FUND 2023-2027 CAPITAL PLAN



(1) Cash from operations is a Non-U.S. GAAP financial measure and reflects cash from operating activities net of dividends and customer contributions.
(2) Net debt reflects regulated and non-regulated debt issuances, net of repayments.
(3) Reflects common shares issued under the Corporation's dividend reinvestment, stock option and employee share purchase plans.
(4) Reflects estimated impact on 2023 and 2024 forecast credit metrics, subject to publication of final regulations.

Predictable Funding Plan

Capital Plan Funded Primarily with Cash from Operations and Debt at Regulated Subsidiaries

- Regulated debt used to repay maturing debt, and fund capital expenditures and operating requirements

Equity Funding Supported by DRIP

- No discrete equity required
- Consistent capital structure expected over planning period

Dividend Growth Guidance Range Provides Incremental Funding Flexibility

4-6%

- Flexibility to fund more capital with internally generated funds

Maintaining Investment-Grade Credit Ratings

- Moody's CFO/Debt and S&P FFO/Debt expected to average ~12% for 2023-2027 before Alternative Minimum Tax (AMT)
- Minimal expected impacts from AMT (<10-20 bps on CFO/Debt)[4]

BEYOND THE PLAN

Inflation Reduction Act

- A catalyst for future transmission investments
- Renewable generation including TEP's IRP(1)
- Interconnecting renewables to the grid
- Electric vehicle infrastructure
- Funding for community transition from fossil fuels

Climate Adaptation & Grid Resiliency

- Investing to withstand more severe weather
- Under various climate scenarios and geographies

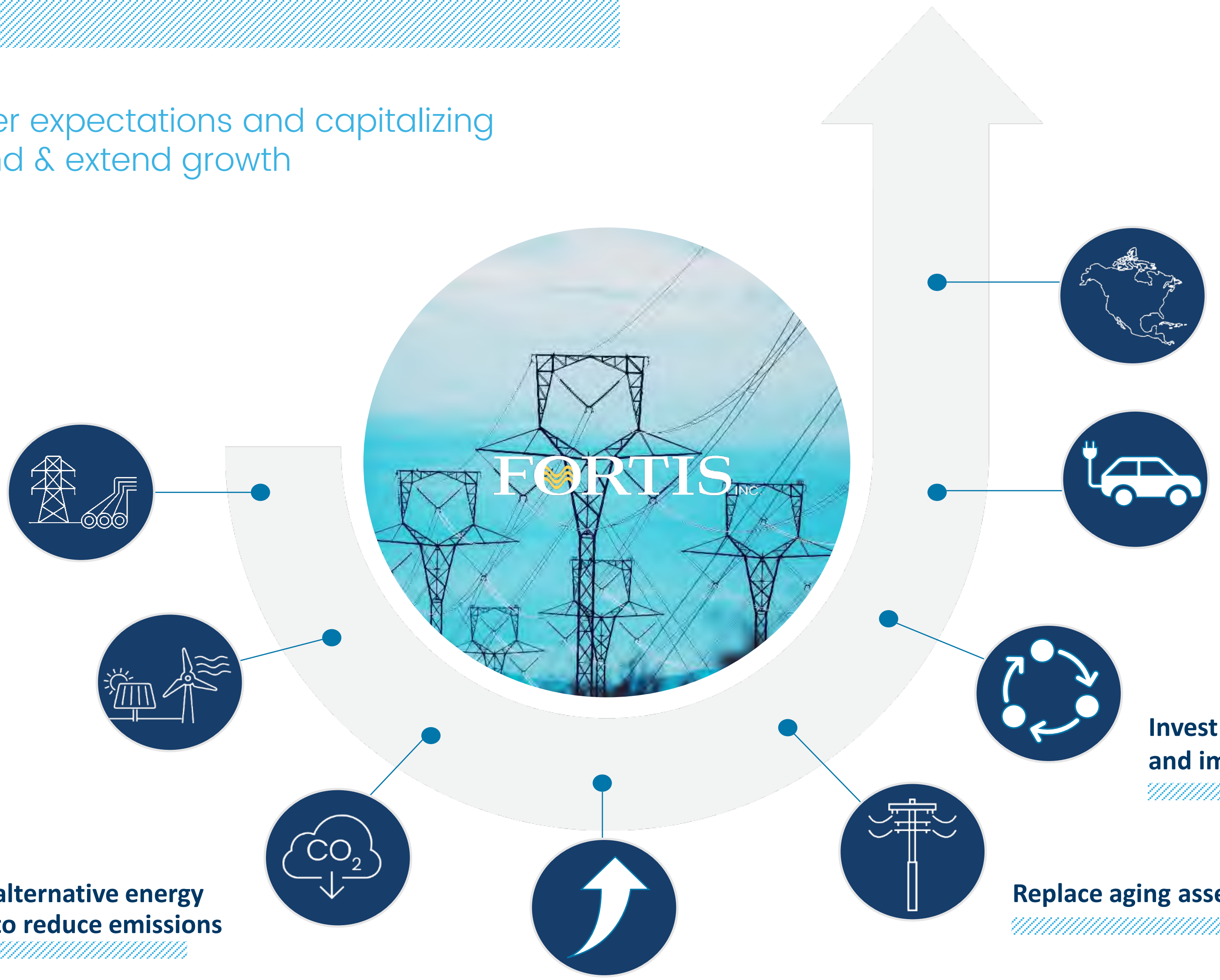
Renewable Fuel Solutions & LNG

- RNG & hydrogen to support British Columbia
- Develop Canadian LNG resources to aid in international energy security and GHG reductions

(1) Incremental opportunity of ~US$2-$4 billion through 2035. Excludes ~US$1B for projects included in the 2023-2027 capital plan, and US$0.5B invested previously, including the Oso Grande Wind project.

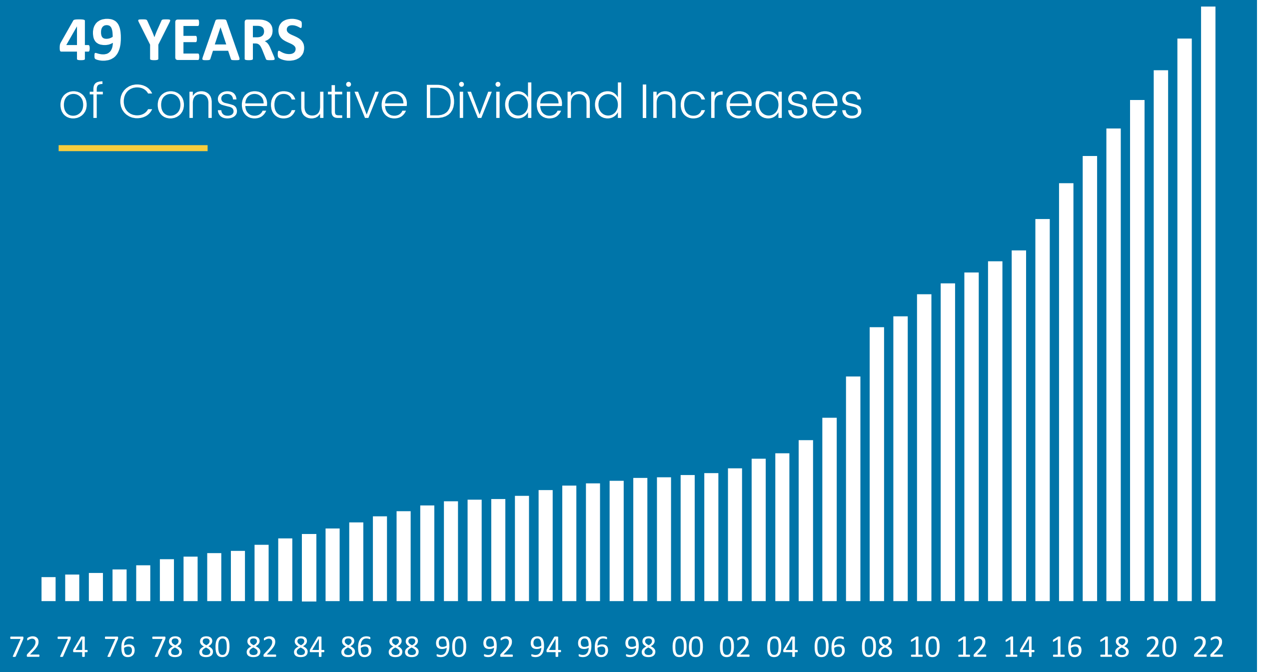
LONG CAPEX RUNWAY

Responding to stakeholder expectations and capitalizing on opportunities to expand & extend growth



DIVIDEND GUIDANCE SUPPORTED BY LONG-TERM GROWTH STRATEGY

49 YEARS
of Consecutive Dividend Increases



4-6%
Annual Dividend Growth Guidance through 2027

ONGOING REGULATORY PROCEEDINGS

ITC
A FORTIS COMPANY

ITC Midwest Capital Structure Complaint Denied – In November 2022, FERC denied the complaint filed by the Iowa Coalition for Affordable Transmission (ICAT) seeking to lower ITC Midwest's equity ratio from 60% to 53%; ICAT filed a request for rehearing with FERC in December 2022

FERC MISO Base ROE – In August 2022, the U.S. Court of Appeals for the DC Circuit vacated certain FERC orders that established the methodology used to calculate the MISO base ROE; matter dates back to complaints filed at FERC in 2013 and 2015; DC Circuit noted FERC did not adequately explain why it reintroduced the risk-premium model in its methodology which increased the MISO Base ROE from 9.88% to 10.02%; timing and outcome remains unknown

Notice of Proposed Rulemaking (NOPR) on Incentives – In April 2021, FERC issued a supplemental NOPR proposing to eliminate the 50-bps regional transmission organization (RTO) adder for transmission owners that have been RTO members for more than three years; stakeholder comments filed in June 2021; the supplemental NOPR and the initial incentive NOPR remain outstanding

UNS
UNS Energy Corporation
A Fortis Company

TEP ACC Rate Case – In June 2022, TEP filed a general rate application seeking new rates to become effective no later than September 1, 2023 using a December 31, 2021 test year

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Customer Information System (CIS) Implementation – In December 2022, the New York Public Service Commission (PSC) released a show cause order to Central Hudson as to why the PSC should not pursue penalties or initiate a prudence proceeding in respect to Central Hudson's new CIS; Central Hudson filed a response in January 2023; timing and outcome of the proceeding remains unknown

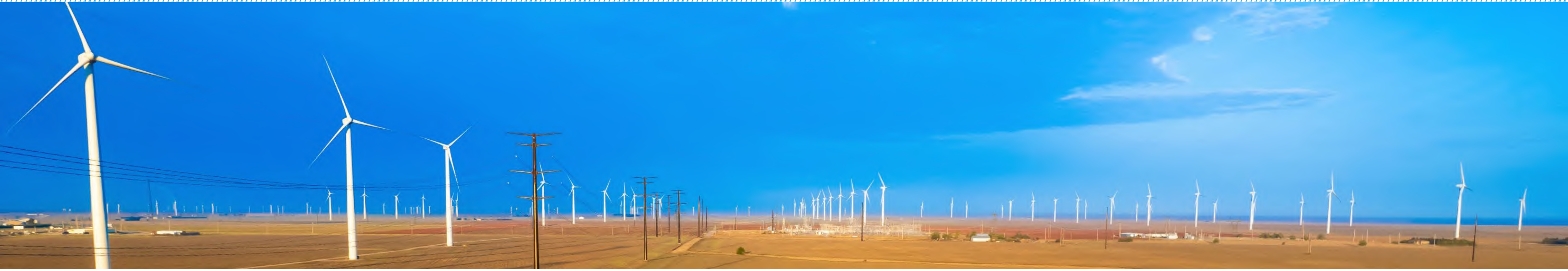
FORTIS BC™

Generic Cost of Capital Proceeding (GCOC) – GCOC proceeding initiated in 2021 includes a review of the common equity component of capital structure and the allowed ROE; proceeding is ongoing with a decision expected in Q2 2023

FORTIS ALBERTA

Cost of Service Application Approved (COS) – In December 2022, the Alberta Utilities Commission approved FortisAlberta's 2023 revenue requirement, reflecting 5% increase in distribution rates

WHY INVEST IN FORTIS?



Focused on ENERGY DELIVERY

Geographic & Regulatory DIVERSITY

4-6% ANNUAL DIVIDEND **Growth Guidance**

SAFE, WELL-RUN **Local Utilities**

LOW-RISK **Growth Profile**

Virtually All REGULATED

ESG **Leader**

INNOVATIVE

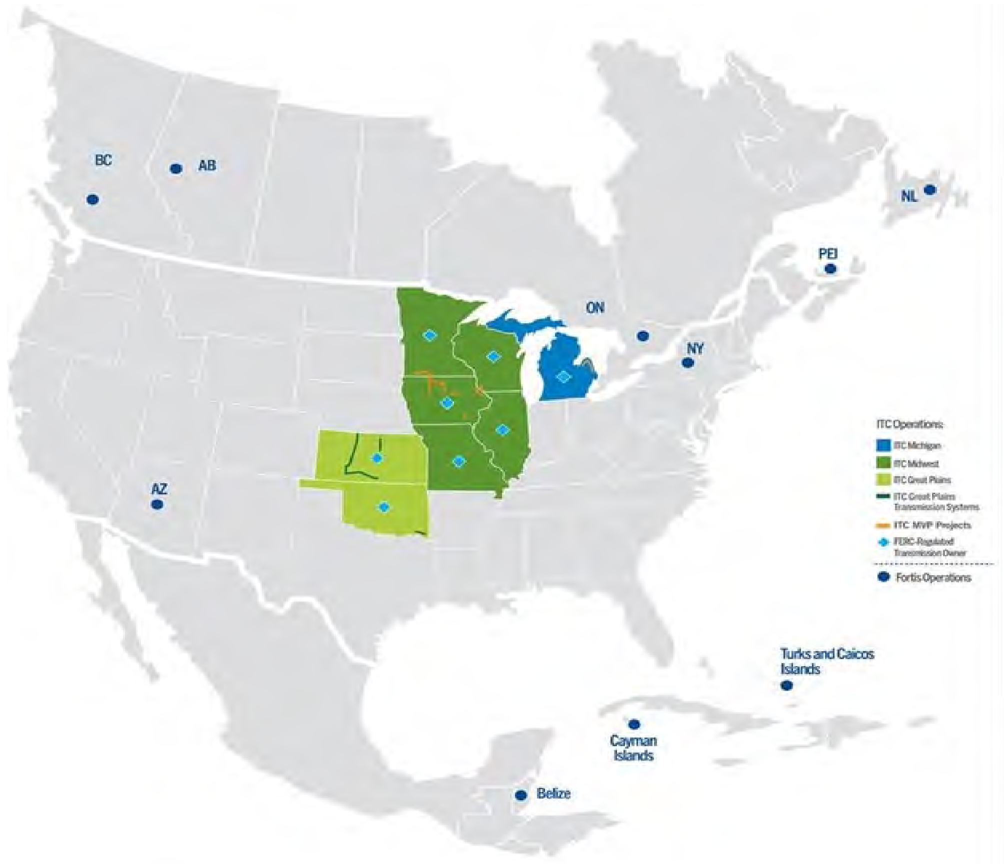
FORTIS

APPENDIX




TABLE OF CONTENTS

ITC HOLDINGS CORP.



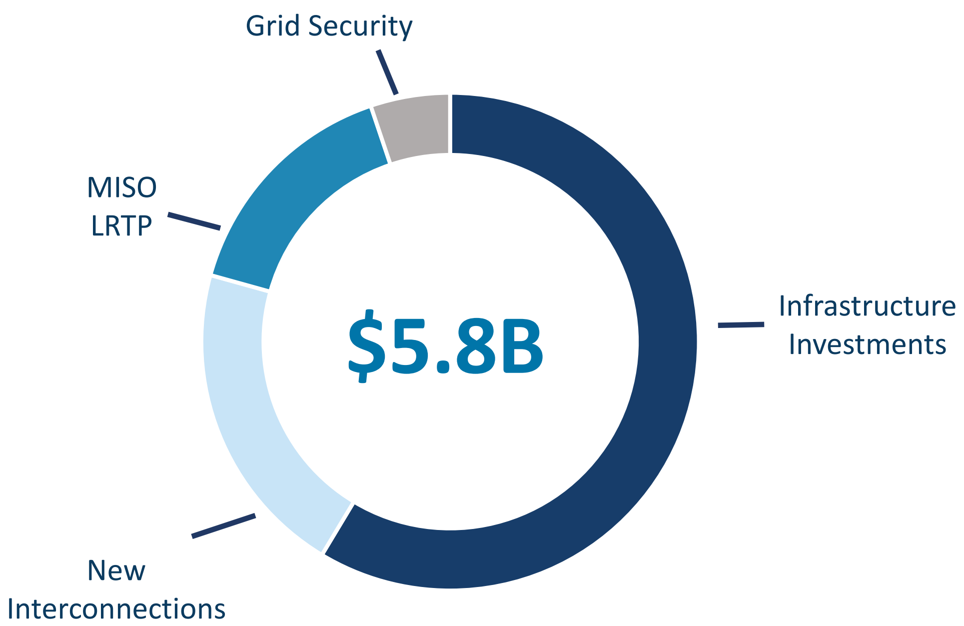
ITC A FORTIS COMPANY

Type of Utility	Transmission
Regulator	FERC
Regulatory Model	Cost of Service with FERC Formula Rates
Current Regulatory Construct	10.77-11.41% ROE on 60% equity
Significant Regulatory Features	Cost-based, forward-looking formula rates with annual true-up
2023F Rate Base(1)	$11.1B
5-Year Rate Base CAGR (2022A-2027F)	6.1%
2022 Assets % of Total Consolidated Regulated Assets(2)	37%
Development Opportunities(3)	Connecting Renewables & Grid Modernization, MISO Long-Range Transmission Plan
Regulatory Proceedings	FERC MISO Base ROE, Notice of Proposed Rulemaking (NOPR) on Incentive Policy & Supplemental NOPR on Regional Transmission Organization Incentive Adder

(1) U.S. dollar-denominated rate base converted at a forecast USD:CAD foreign exchange rate of 1.30.
(2) Includes goodwill
(3) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

ITC CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL[1]



$3.4B Infrastructure Investments

Rebuild, reliability, resiliency, system efficiencies, increased capacity, circuit overloads, pocket load growth

$1.2B New Interconnections

Supports economic development, load interconnection requests and changes in generation sources

$900M MISO Long-Range Transmission Plan

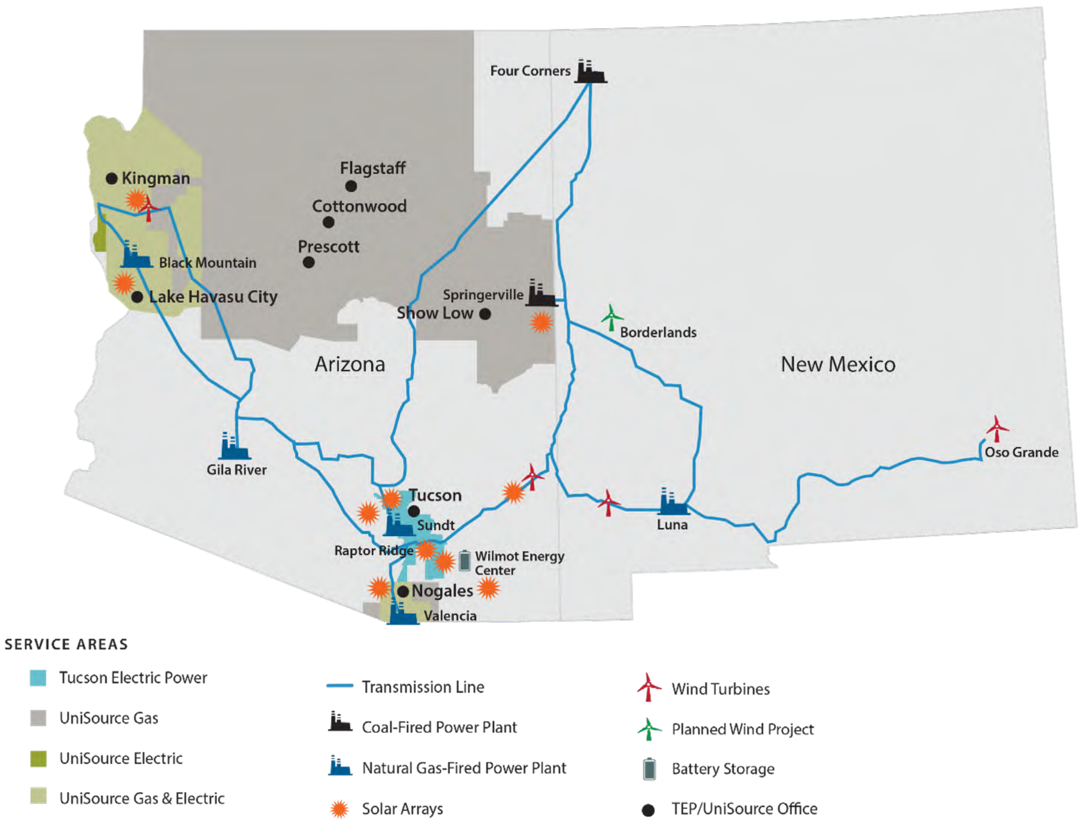
Includes portion of investments for Tranche 1

$300M Grid Security

Physical and cyber hardening along with technology upgrades

(1) U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30.

UNS ENERGY



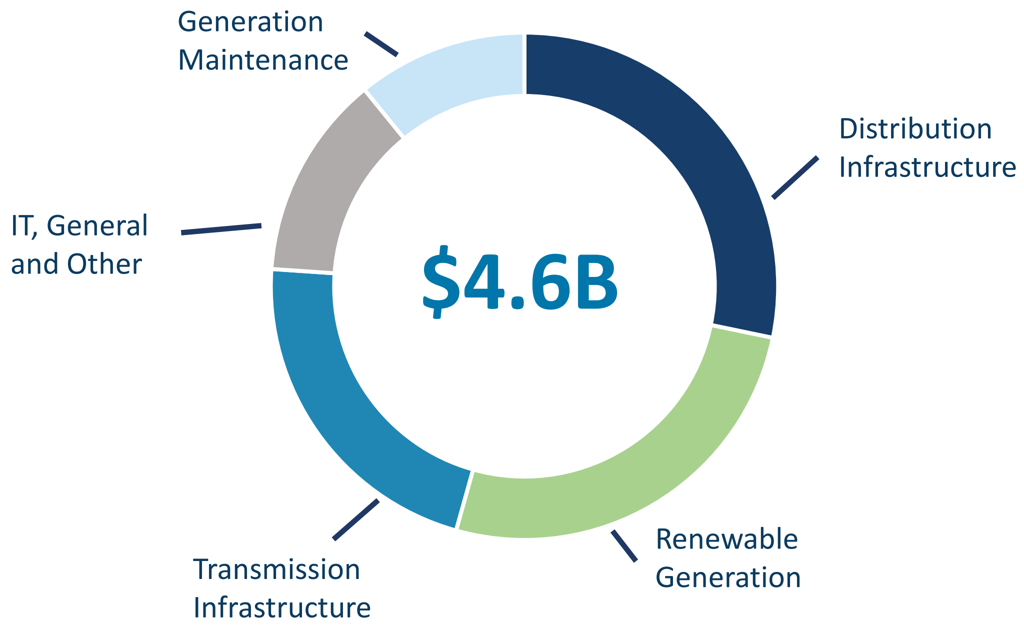
UNS Energy Corporation
A Fortis Company

	Tucson Electric	UNS Electric	UNS Gas
Type of Utility	Electricity		Gas Distribution
Regulator	Arizona Corporation Commission & FERC		
Regulatory Model	Cost of service/historical test year & FERC formula transmission rates		
Current Regulatory Construct[(1)]	9.15% ROE on 53.0% equity	9.50% ROE on 52.8% equity	9.75% ROE on 50.8% equity
2023F Rate Base[(2)]	$7.0B		
5-Year Rate Base CAGR (2022A-2027F)	6.3%		
2022 Assets % of Total Consolidated Regulated Assets[(3)]	20%		
Development Opportunities[(4)]	Renewables, Storage & Electric Transmission		
Regulatory Proceedings	TEP General Rate Application & UNS Electric General Rate Application		

(1) Allowed ROE and equity based on Arizona Corporation Commission regulatory authority.
(2) U.S. dollar-denominated rate base converted at a forecast USD:CAD foreign exchange rate of 1.30.
(3) Includes goodwill
(4) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

UNS CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL[1]



$1.3B Distribution Infrastructure
Grid resiliency and modernization

$1.2B Renewable Generation
Energy storage, renewable investments

$1.0B Transmission Infrastructure
Vail-to-Tortolita, new substations

$600M IT, General and Other
Supports technology, efficiency and sustainment

$500M Generation Maintenance

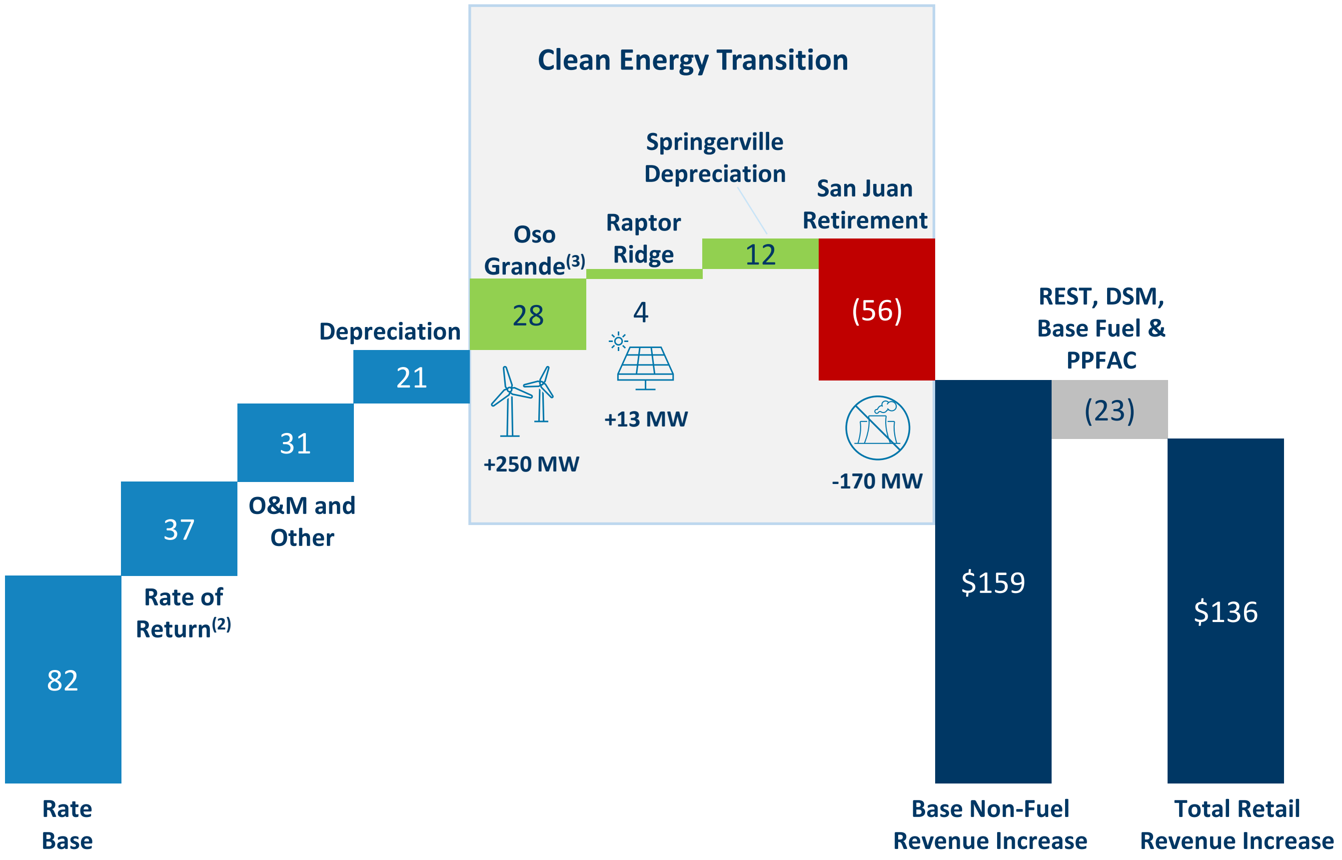
(1) U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30.

TEP GENERAL RATE APPLICATION

APPLICATION SUPPORTS TEP'S CLEAN ENERGY TRANSITION AND CONTINUED DELIVERY OF SAFE AND RELIABLE SERVICE

	2019 Rate Case		2022 Rate Case	
	Application	Decision	Application	Staff Testimony
Test Year	December 31, 2018		December 31, 2021	
New Rates Effective	May 2020	January 2021	September 2023	
Rate Base	US$2.7B	US$2.7B	US$3.6B[1]	US$3.6B
Non-Fuel Revenue Increase	US$115M	US$58M	US$159M	US$97-$108M
Equity/Debt	53%/47%	53%/47%	54%/46%	54%/46%
ROE	10.35%	9.15%	10.25%	9.60%

REQUESTED REVENUE REQUIREMENT (US$M)



(1) Includes US$0.2B in post-test year adjustments.
(2) Includes fair value increment.
(3) Net of production tax credits.

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ARIZONA FOCUSED ON RENEWABLES

TEP INTEGRATED RESOURCE PLAN FILED IN 2020

- Next IRP expected in 2023

Coal-free
generation mix by 2032

>70% renewable power by 2035

Over 50 million tonnes of CO_2 emissions
avoided over 15 years

250 MW
Oso Grande ✓

100 MW
Wilmot Solar (1)(2) ✓

99 MW
Borderlands(1) ✓

3,400 MW Planned Additions of Wind, Solar and Storage

2021

2022-2035

1,073 MW
Planned Coal Retirements

2022
170 MW
San Juan ✓

2027
387 MW
Springerville Unit #1

2031
110 MW
Four Corners

2032
406 MW
Springerville Unit #2

(1) Power purchase agreement
(2) Wilmot also has 30 MW of battery storage

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RELIABLE & AFFORDABLE SERVICE DURING CLEAN ENERGY TRANSITION

TEP's goal is to transition to a cleaner grid while maintaining affordable rates and reliable service for our customers

1,073 MW Planned Coal Retirements by 2032

Current

Steel for Fuel Transition

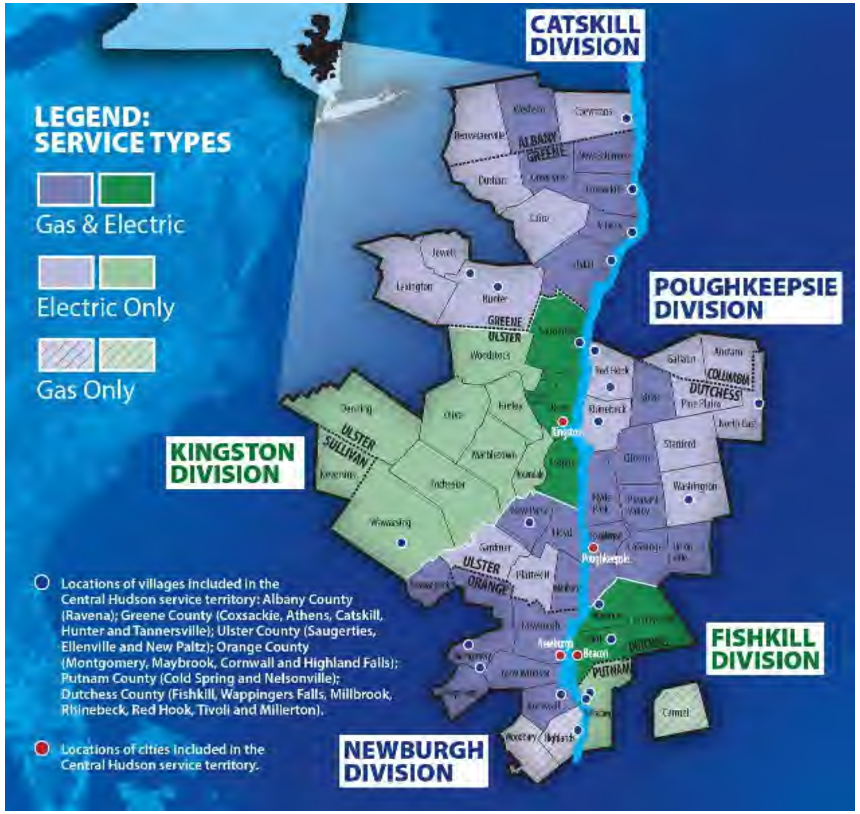
- Significant fuel and fixed O&M costs replaced with capital investment
- Coal exit plan provides time for development of impacted community transition assistance
- ~492 MW of wind, solar and energy storage resources added in 2021-2022
- All-Source RFP launched in April 2022 targeting both energy and firm capacity

3,400 MW of Planned Wind, Solar and Storage Resources

Future

FORTIS

CENTRAL HUDSON

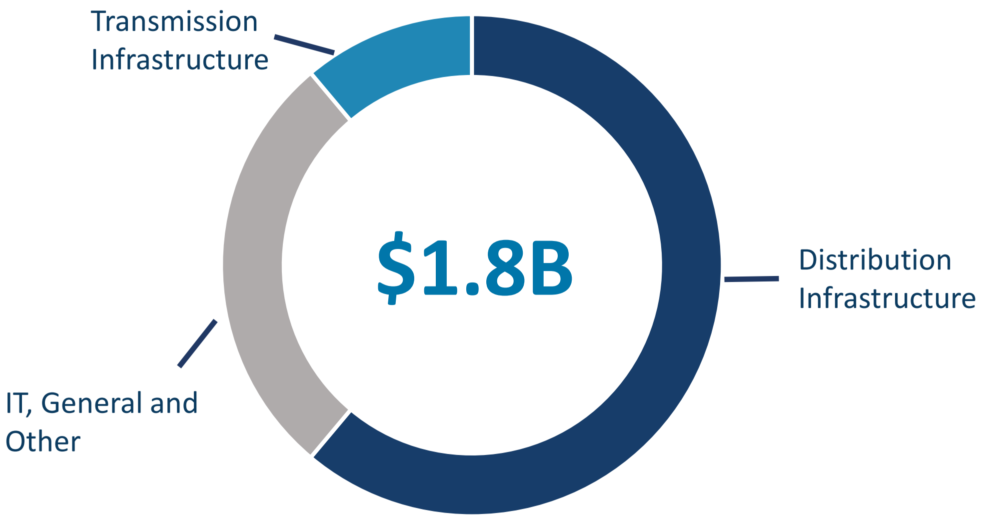


Type of Utility	Electric and Gas Transmission & Distribution
Regulator	New York State Public Service Commission
Regulatory Model	Cost of service on future test year
Current Regulatory Construct(1)	9.0% ROE on 49% equity
Significant Regulatory Features	Revenue decoupling
2023F Rate Base(2)	$2.7B
5-Year Rate Base CAGR (2022A-2027F)	6.4%
2022 Assets % of Total Consolidated Regulated Assets(3)	8%
Development Opportunities(4)	Grid Modernization & NY Transco Expansion
Regulatory Proceedings	Customer Information System Implementation

(1) In November 2021, the New York Public Service Commission approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year.
(2) U.S. dollar-denominated rate base converted at a forecast USD:CAD foreign exchange rate of 1.30.
(3) Includes goodwill
(4) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

CENTRAL HUDSON CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL[(1)]



$1.1B Distribution Infrastructure
Distribution automation and modernization

$500M IT, General and Other Modernization
Building the Workforce of the Future

$200M Transmission Infrastructure
Replacement of aging infrastructure

(1) U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30.

FORTISBC

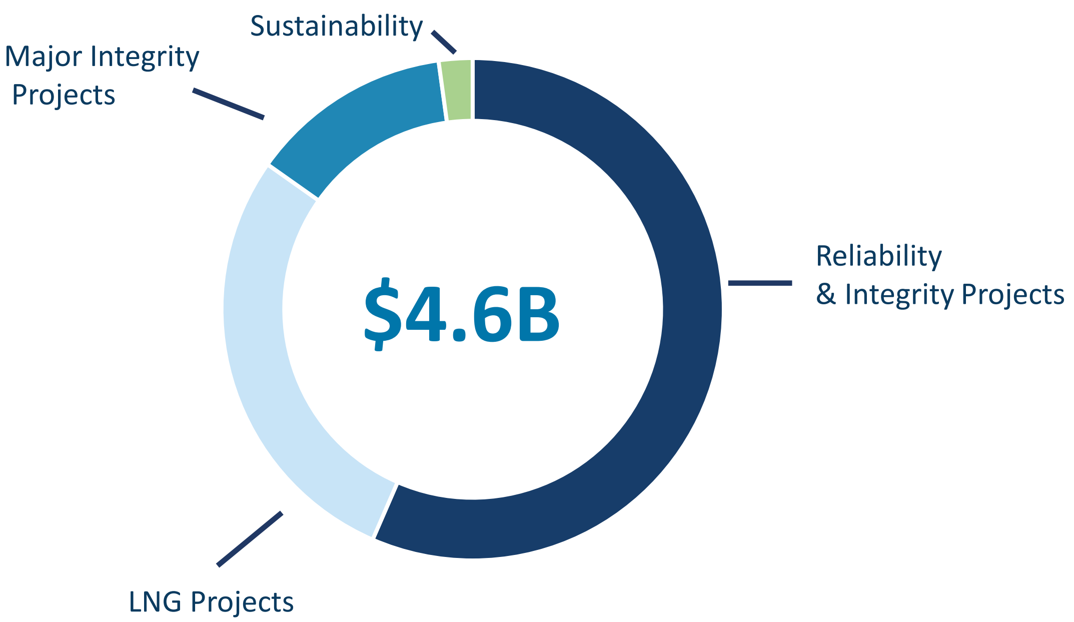
FORTIS BC™

	FortisBC Energy	FortisBC Electric
Type of Utility	Gas distribution	Electricity
Regulator	British Columbia Utilities Commission	
Regulatory Model	Cost of service with incentive mechanisms	
Current Regulatory Construct	8.75% ROE on 38.5% equity	9.15% ROE on 40.0% equity
Significant Regulatory Features	Multi-year rates with revenue deferrals – changes in consumption and commodity costs do not impact earnings	
2023F Rate Base	\$5.8B	\$1.7B
5-Year Rate Base CAGR (2022A-2027F)	6.9%	4.3%
2022 Assets % of Total Consolidated Regulated Assets(1)	14%	4%
Development Opportunities(2)	LNG for Marine Bunkering, LNG Bulk Export & Gas Infrastructure	N/A
Regulatory Proceedings	Generic Cost of Capital	

(1) Includes goodwill
(2) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

FORTISBC CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL



$2.6B Reliability & Integrity Investments

Ongoing maintenance requires significant capital investment
Includes customer growth and general plant investment

$1.3B LNG Projects

Tilbury 1B
Tilbury LNG Resiliency Tank
Eagle Mountain Woodfibre Gas Line Project

$600M Major Integrity Projects

Advanced Metering Infrastructure Project
Okanagan Capacity Upgrade

$100M Sustainability

Renewable gas projects
Natural gas for transportation

FORTIS

FORTISALBERTA

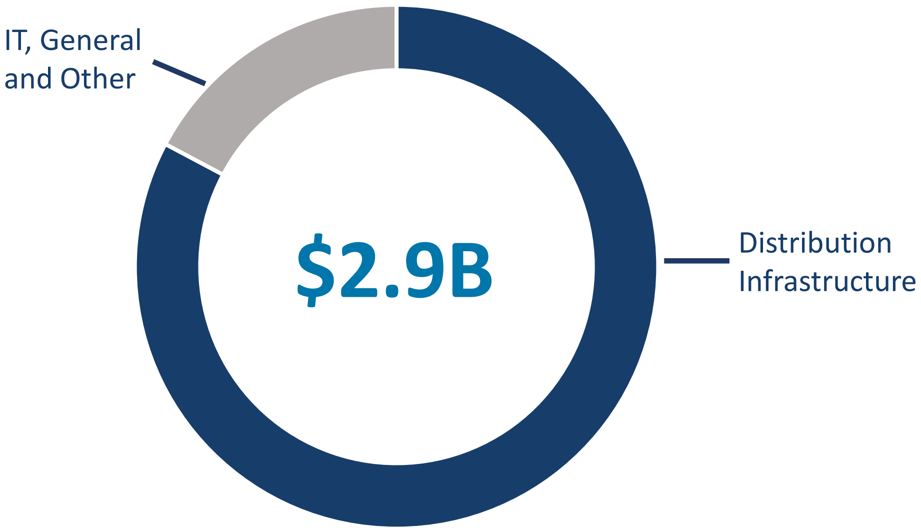
FORTIS ALBERTA

Type of Utility	Electricity distribution
Regulator	Alberta Utilities Commission
Regulatory Model	PBR
Current Regulatory Construct	8.5% ROE on 37% equity
Significant Regulatory Features	~85% of revenue derived from fixed-billing determinants
2023F Rate Base	$4.2B
5-Year Rate Base CAGR (2022A-2027F)	4.7%
2022 Assets % of Total Consolidated Regulated Assets[1]	9%
Regulatory Proceedings	2024 Generic Cost of Capital Proceeding & Third PBR Term

(1) Includes goodwill.

FORTISALBERTA CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL



$2.4B Distribution Infrastructure

Safety & reliability of distribution assets, meter upgrades, pole management program, modernization

$500M IT, General and Other

OTHER ELECTRIC UTILITIES

	NEWFOUNDLAND POWER A FORTIS COMPANY	MARITIME ELECTRIC A FORTIS COMPANY	FORTIS ONTARIO (1)
Type of Utility		Electricity	
Regulator	Newfoundland and Labrador Board of Commissioners of Public Utilities	Island Regulatory and Appeals Commission	Ontario Energy Board
Regulatory Model	Cost of service on future test year	Cost of service on future test year	Cost of service with incentives
Current Regulatory Construct	8.50% ROE on 45% equity	9.35% ROE on 40% equity	8.52% - 9.36% ROE on 40% equity(2)
2023F Rate Base	$1.3B	$0.5B	$0.7B(1)
5-Year Rate Base CAGR (2022A-2027F)	4.2%	8.1%	15.3%(3)
2022 Assets % of Total Consolidated Regulated Assets(4)	3%	1%	1%
Development Opportunities(5)	Grid Modernization	Grid Modernization	Municipal Utility Consolidation
Regulatory Proceedings	-	General Rate Application	-

(1) Includes Canadian Niagara Power, Cornwall Electric, Algoma Power and Fortis' 39% ownership of the Wataynikaneyap Transmission Power Project.
(2) Allowed ROE is 8.52% for Algoma Power, 8.66% for Canadian Niagara Power distribution, 9.30% for Canadian Niagara Power transmission and 9.36% for Wataynikaneyap Transmission Power Project. Cornwall Electric operates under a franchise agreement with a price-cap and commodity cost flow through and, therefore, is not regulated with reference to an allowed ROE.
(3) Reflects Fortis' 39% ownership of the Wataynikaneyap Transmission Power Project
(4) Includes goodwill
(5) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

OTHER ELECTRIC UTILITIES (CONTINUED)

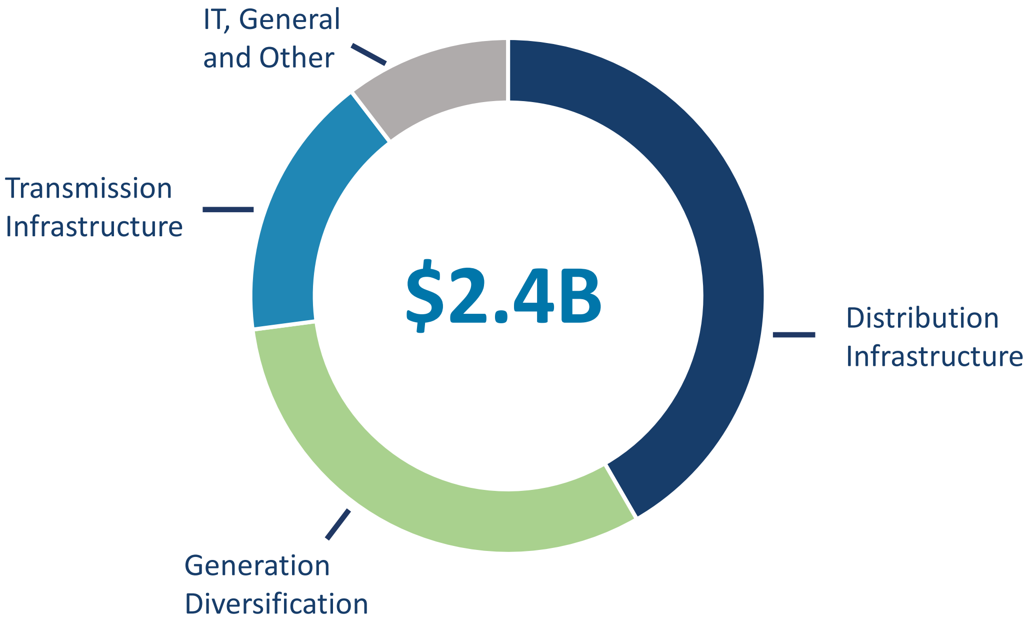
	Caribbean Utilities [1]	FORTIS TCI
Type of Utility	Electricity	
Regulator	Utility Regulation and Competition Office	Government of the Turks and Caicos Islands
Regulatory Model	Cost of service	Cost of service
2022 Achieved ROE	10.8%	10.8%
2023F Rate Base[2]	$0.8B	$0.5B
5-Year Rate Base CAGR (2022A-2027F)	10.6%	3.3%
2022 Assets % of Total Consolidated Regulated Assets[3]	2%	1%
Development Opportunities[4]	Grid Modernization, Battery Storage & Renewables	

(1) Fortis has an approximate 60% controlling interest in Caribbean Utilities Company, Ltd.
(2) U.S. dollar-denominated rate base converted at a forecast USD:CAD foreign exchange rate of 1.30.
(3) Includes goodwill
(4) Development opportunities are not included in the base capital forecast and represent incremental capital spending.

FORTIS

OTHER ELECTRIC CAPITAL INVESTMENT OVERVIEW

2023-2027 CAPITAL[(1)]



$1B Distribution Infrastructure
Newfoundland Power, Maritime Electric and Caribbean Utilities

$750M Generation Diversification
Caribbean Utilities shift to cleaner energy

$400M Transmission Infrastructure
Maritime Electric
Wataynikaneyap Transmission Power Project

$250M IT, General and Other

(1) U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30.

2022-2027 RATE BASE BY BUSINESS UNIT

Rate Base

($BILLIONS, EXCEPT FOR CAGR)	2022A	2023F	2024F	2025F	2026F	2027F	5-YEAR CAGR to 2027
Regulated - Independent Electric Transmission							
ITC[1]	10.5	11.1	11.9	12.5	13.2	14.1	6.1%
Regulated – U.S. Electric & Gas							
UNS Energy	6.7	7.0	7.4	7.8	8.5	9.1	6.3%
Central Hudson	2.6	2.7	2.9	3.1	3.4	3.6	6.4%
Total Regulated – U.S. Electric & Gas	9.3	9.7	10.3	10.9	11.9	12.7	6.3%
Regulated - Canadian & Caribbean Electric & Gas							
FortisBC Energy	5.4	5.8	6.0	6.5	7.0	7.6	6.9%
FortisAlberta	4.0	4.2	4.4	4.6	4.8	5.0	4.7%
FortisBC Electric	1.6	1.7	1.7	1.8	1.9	2.0	4.3%
Other Electric[2]	3.3	3.8	4.1	4.4	4.5	4.7	7.7%
Total Regulated - Canadian & Caribbean Electric & Gas	14.3	15.5	16.2	17.3	18.2	19.3	6.2%
Total Rate Base Forecast	**34.1**	**36.3**	**38.4**	**40.7**	**43.3**	**46.1**	**6.2%**

Note: U.S. dollar-denominated rate base converted at a foreign exchange rate of 1.30 for 2022-2027. CAGR, as defined in the 2022 MD&A.

(1) Fortis has an 80.1% controlling ownership interest in ITC; rate base represents 100% ownership.
(2) Includes Eastern Canadian and Caribbean electric utilities.

FORTIS

2023-2027 CAPITAL PLAN BY BUSINESS UNIT

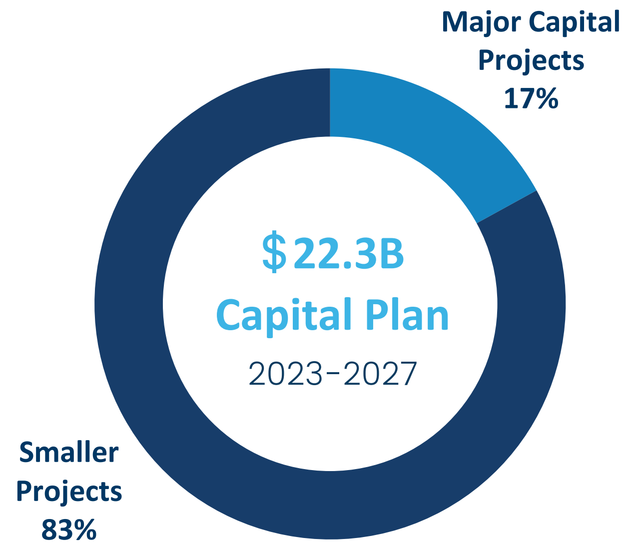
	Capital Plan[1]					
($MILLIONS)	2023F	2024F	2025F	2026F	2027F	2023-2027 TOTAL
Regulated - Independent Electric Transmission						
ITC	1,103	1,177	1,137	1,180	1,220	5,817
Regulated – U.S. Electric & Gas						
UNS Energy	1,006	690	986	1,027	891	4,600
Central Hudson	384	343	418	334	360	1,839
Total Regulated – U.S. Electric & Gas	1,390	1,033	1,404	1,361	1,251	6,439
Regulated - Canadian & Caribbean Electric & Gas						
FortisBC Energy	536	748	851	724	1,087	3,946
FortisAlberta	556	568	564	588	599	2,875
FortisBC Electric	132	140	143	147	141	703
Other Electric[2]	579	465	451	439	419	2,353
Total Regulated - Canadian & Caribbean Electric & Gas	1,803	1,921	2,009	1,898	2,246	9,877
Non-Regulated	31	28	29	31	35	154
Total Capital Plan	**4,327**	**4,159**	**4,579**	**4,470**	**4,752**	**22,287**

(1) Capital Plan is a forward-looking Non-U.S. GAAP financial measure calculated in same manner as Capital Expenditures. Refer to 2022 MD&A for the Non-U.S. GAAP reconciliation. U.S. dollar-denominated capital expenditures converted at a forecast USD:CAD foreign exchange rate of 1.30.

(2) Includes Eastern Canadian and Caribbean electric utilities.

MAJOR CAPITAL PROJECTS

($ Millions)	2023-2027 PLAN	ESTIMATED COMPLETION DATE
ITC MISO Long-Range Transmission Plan(1)	923	Post-2027
UNS Energy Renewable Generation(2)	417	Various
UNS Energy Vail-to-Tortolita Transmission Project	378	2027
FortisBC Tilbury LNG Storage Expansion	504	Post-2027
FortisBC AMI Project	421	Post-2027
FortisBC Eagle Mountain Woodfibre Gas Line Project(3)	420	2027
FortisBC Tilbury 1B Project	343	Post-2027
FortisBC Okanagan Capacity Upgrade	200	2025
Wataynikaneyap Transmission Power Project(4)	137	2024



Note: Major capital projects are defined as projects, other than ongoing maintenance projects, individually costing $200M or more in the forecast period. Total project costs include forecasted capitalized interest and non-cash equity component of allowance for funds used during construction, where applicable.

(1) Reflects investments associated with six projects in states with rights of first refusal for incumbent transmission owners. Total estimated transmission investments of US$1.4-$1.8B through 2030 inclusive of the US$700M reflected in the 2023-2027 capital plan.
(2) Reflects expected investments in renewable generation to support TEP's Integrated Resource Plan. Excludes energy storage investments not yet defined.
(3) Capital plan is net of forecast customer contributions.
(4) Represents Fortis' 39% share of the estimated capital spending for the project.

MACRO OUTLOOK & ASSUMPTIONS

Foreign Exchange

- USD:CAD FX Rate of 1.30 for 2023-2027
- 65% of operating earnings[(1)] / 60% of capital plan from U.S. & Caribbean
- +/- $0.05 change in USD:CAD – EPS: $0.06[(2)] Five-year capital plan: $500M

Interest Rates

- Primary exposure to rising rates at Fortis Inc. and ITC Holdings (non-regulated)
- Average annual near-term non-regulated maturities of ~US$400M at ~4% weighted average rate for 2023-2025

Inflation

- Plan assumes moderating inflation levels with return to historical averages in 2025
- +/- 100 bps in inflation impacts five-year capital plan by ~$200M

ROE & Equity Ratio

(EPS Impact)	ROE +/- 25 bps	Equity +/- 100 bps
ITC	$0.03	$0.02
UNS Energy	$0.02	$0.01
FortisBC Energy	$0.01	$0.01

(1) Non-U.S. GAAP financial measure as at December 31, 2022. Excludes Net Expense of Corporate and Other segment.
(2) Foreign exchange EPS sensitivity inclusive of the Corporation's hedging activities.

Q4 SALES TRENDS

	RETAIL ELECTRIC SALES	Q4 2022 vs. Q4 2021 SALES TRENDS
ITC A FORTIS COMPANY	N/A	• Peak load down 5% due to milder weather impacts and economic conditions
UNS UNS Energy Corporation A Fortis Company(1)	+3%	• Increase primarily due to favourable weather impacts and customer growth; excluding weather impacts, retail sales up 1%
People. Power. Possibilities. Central Hudson A FORTIS COMPANY	-4%	• Residential sales down 7% due to lower average consumption; commercial and industrial (C&I) sales down 1%
FORTIS ALBERTA	+1%	• Residential sales up 3% due to colder temperatures; C&I sales up 1% due to higher load from industrial customers
FORTIS BC(2)	+4%	• Residential electric sales up 2% due to colder temperatures; C&I electric sales up 8%
Other Electric	-	• Eastern Canadian residential sales flat and C&I sales up 2% • Caribbean sales up 3% due to increased tourism-related activities

(1) Excludes wholesale sales at UNS Energy.
(2) Reflects electric sales at FortisBC Electric. Gas sales at FortisBC up 1% primarily due to higher average consumption by residential and commercial customer due to colder temperatures.

2022 SALES TRENDS

	RETAIL ELECTRIC SALES	2022 vs. 2021 SALES TRENDS
ITC A FORTIS COMPANY	N/A	• Peak load up 1% due to favourable weather impacts
UNS Energy Corporation A Fortis Company[1]	+1%	• Increase primarily due to higher cooling load associated with warmer temperatures and customer growth; Excluding weather impacts, retail sales flat
Central Hudson A FORTIS COMPANY	-	• Residential sales down 1% due to lower average consumption and C&I up 2%
FORTIS ALBERTA	+2%	• Residential sales down 2% due to milder weather in Q3; C&I up 3% due to higher load from industrial customers, higher average consumption from commercial customers, and customer additions
FORTIS BC[2]	+2%	• Residential electric sales flat; C&I electric sales up 5% due to higher average consumption by industrial customers
Other Electric	+2%	• Eastern Canadian residential and C&I sales each up 2% • Caribbean sales up 3% due to increased tourism-related activities

(1) Excludes wholesale sales at UNS Energy.
(2) Reflects electric sales at FortisBC Electric. Gas sales at FortisBC Energy up 1% primarily due to higher average consumption by residential and commercial customer due to colder temperatures.

FORTIS

LIMITED PENSION EXPOSURE

Defined Benefit Pension Plans

- 101% of $3.1B pension benefit obligation funded at December 31, 2022
- Allocation of plan assets at December 31, 2022
  - Equities – 48%
  - Fixed income – 43%
  - Other – 9%
- ~80% of pension assets subject to regulatory mechanisms
  - UNS pension plan assets (~$0.6B) not subject to automatic regulatory mechanisms
  - No significant change expected in UNS' 2023 pension expense based on actuarial calculations and asset valuations at December 31, 2022

Certain U.S. Retirement Benefits

- Certain retirement benefits funded through trusts are subject to market changes each quarter
- Decline in market values in 2022 resulted in year-over-year unfavourable EPS impact of $0.04
- ~US$150M in assets at December 31, 2022

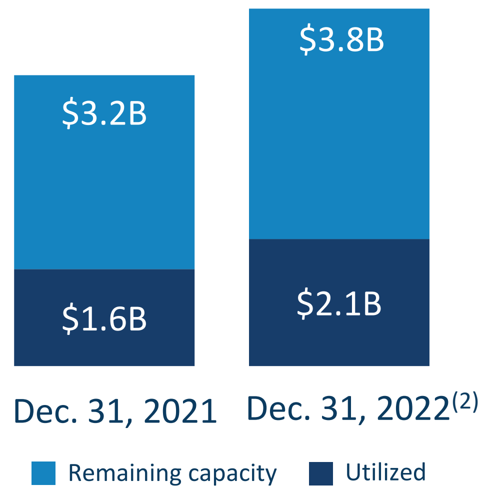
FORTIS

STRONG LIQUIDITY & CREDIT METRICS

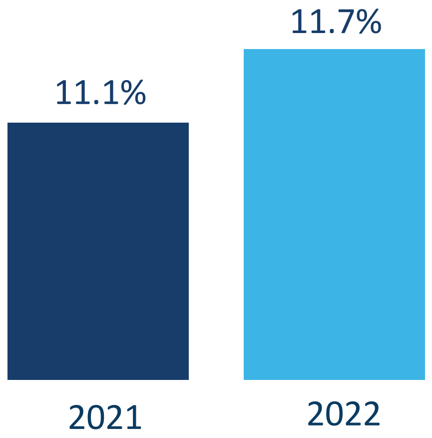
Active in Debt Markets

- Over $3B in long-term debt raised in 2022
  - Weighted average rate of 3.9%[1]
  - Terms ranging from 5-30 years
- Includes ~$400M in green debt
  - US$170M at ITC
  - $150M at FortisBC Energy

Ample Credit Facilities



Improving CFO/Debt Metrics[3]



(1) Refer to Slide 44 for additional details surrounding Fortis' debt issuances in 2022. Weighted average interest rate calculated using the effective interest rate, inclusive of hedging activities.
(2) In May 2022, Fortis Inc. entered a 1-year, unsecured US$500M non-revolving term credit facility.
(3) CFO/Debt calculated in accordance with Moody's methodology. Excluding the foreign exchange impact on debt, CFO/Debt would be 12.0% and 11.2% in 2022 and 2021, respectively.

FORTIS

LONG-TERM DEBT ISSUANCES

Over $3B in Long-Term Debt issued in 2022

- Fortis Inc. – $500M unsecured 7-year 4.43% notes(1)
- ITC
  - US$300M secured mortgage bonds(2)
  - US$75M secured 30-year 3.05% notes
  - US$600M unsecured 5-year 4.95% notes(3)
- UNS Energy – US$325M unsecured 10-year 3.25% notes
- Central Hudson – US$220M unsecured notes(4)
- FortisBC Energy – $150M unsecured 30-year 4.67% debentures
- FortisAlberta – $125M unsecured 30-year 4.62% debentures
- FortisBC Electric – $100M unsecured 30-year 4.16% debentures
- Newfoundland Power - $75M first mortgage 30-year 4.20% bonds
- Caribbean Utilities – US$80M unsecured 30-year 5.88% notes

(1) The Corporation entered into cross-currency interest rate swaps to effectively convert the debt into US$391M with an interest rate of 4.34%.

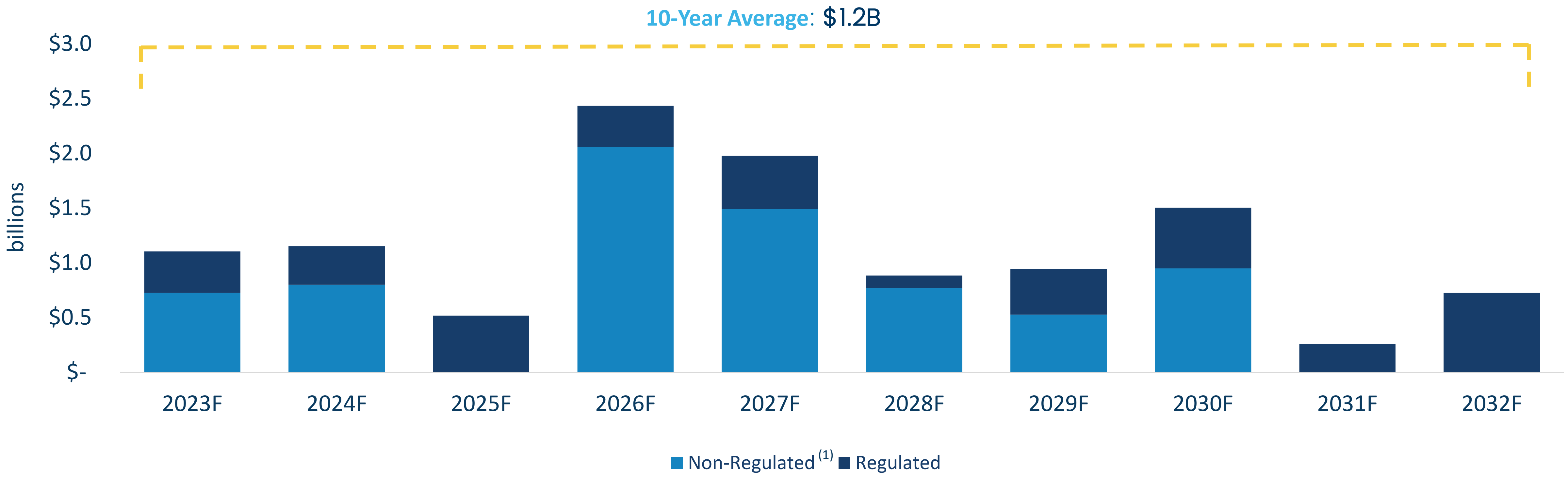
(2) Includes US$150M 30-year 2.93% bonds issued in January, US$75M 30-year 4.53% bonds issued in October and US$75M 5-year 3.87% bonds issued in October. US$170M of the US$300M secured mortgage bonds proceeds used to fund eligible green projects.

(3) Prior to the issuance in September 2022, ITC executed US$450M in interest rate swaps to manage refinancing risk associated with the debt issuance. Inclusive of the hedging activities, the effective interest rate on the US$600M debt is 3.54%.

(4) Includes US$50M 5-year 2.37% notes issued in January, US$60M 7-year 2.59% notes issued in January, US$100M 10-year 5.07% notes issued in September and US$10M 30-year 5.42% notes issued in September.

FORTIS

DEBT MATURITIES



Note: Debt as at December 31, 2022 and excludes any new debt issuances during the forecast period. Excludes repayments of finance leases along with the current portion of credit facilities, which are assumed to be extended by one-year annually.

(1) Includes non-regulated debt issued at Fortis Inc. and ITC Holdings.

FORTIS

INVESTMENT-GRADE CREDIT RATINGS

COMPANY	S&P Global	Moody's	Morningstar DBRS
Fortis Inc.	A-(1)	Baa3	A (low)
ITC Holdings Corp.	A-(1)	Baa2	n/a
ITC Regulated Subsidiaries	A	A1	n/a
TEP	A-	A3	n/a
Central Hudson	BBB+	Baa1	n/a
FortisBC Energy	n/a	A3	A
FortisBC Electric	n/a	Baa1	A (low)
FortisAlberta	A-	Baa1	A (low)
Newfoundland Power	n/a	A2	A

(1) S&P credit ratings for Fortis Inc. and ITC Holdings Corp. reflect the issuer credit ratings. The unsecured debt rating for Fortis Inc. and ITC Holdings Corp. is BBB+.

FORTIS

STRONG LEADERSHIP TEAM

Fortis Inc. Exec.


David Hutchens
President & CEO


Jocelyn Perry
EVP, CFO


Jim Reid
EVP, Sustainability & CLO


Gary Smith
EVP, Operations & Innovation


Stuart Lochray
Sr. VP Capital Markets & Business Development


Stephanie Amaimo
VP, Investor Relations


Julie Avery
VP, Controller


Karen Gosse
VP, Finance


Ron Hinsley
VP, IT & CIO


Karen McCarthy
VP, Communications & Corporate Affairs


Regan O’Dea
VP, General Counsel


Kevin Woodbury
VP, Innovation & Technology

Utility CEOs


Linda Apsey
ITC


Chris Capone
Central Hudson


Roger Dall’Antonia
FortisBC


Ruth Forbes
FortisTCI


Susan Gray
UNS Energy


Scott Hawkes
FortisOntario


Richard Hew
Caribbean Utilities


Kay Menzies
Fortis Belize


Gary Murray
Newfoundland Power


Jason Roberts
Maritime Electric


Janine Sullivan
FortisAlberta

FORTIS

Moody's Investors Service Credit Opinion
9 December 2022
for FortisBC Energy Inc.
as filed in
British Columbia Utilities Commission
2022 Generic Cost of Capital Proceeding

Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
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Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

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www.fortisbc.com

December 12, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: British Columbia Utilities Commission (BCUC) 2022 Generic Cost of Capital (GCOC) Proceeding

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC) Responses to Undertakings

On November 23, 2022, in compliance with BCUC Order G-237-22, FortisBC filed its responses to undertakings from the Oral Hearing of November 7, 2022 to November 9, 2022 in the above referenced proceeding.

In FortisBC's response to Undertaking No. 3 (filed as part of Exhibit B1-50), FortisBC stated that it would file Moody's credit rating reports for FEI and FBC in this proceeding if they became available prior to close of the evidentiary record on December 9, 2022. Moody's credit rating report for FEI was published in late hours of Friday, December 9, 2022 and is attached to this letter.

FortisBC notes that Moody's published its credit rating report for FBC on December 12, 2022, after the close of the evidentiary record. FortisBC is prepared to file FBC's credit rating report in this proceeding if requested by the BCUC.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
9 December 2022

Update

Send Your Feedback

RATINGS

FortisBC Energy Inc.

Domicile	Vancouver, British Columbia, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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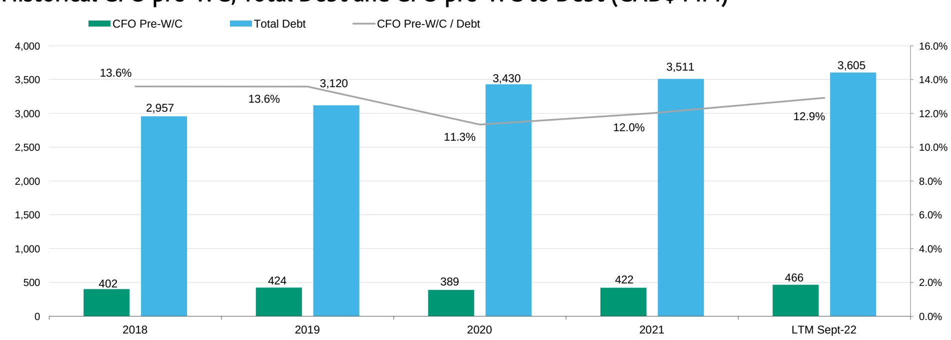
FortisBC Energy Inc.

Update to credit analysis

Summary

FortisBC Energy Inc.'s (FEI) credit profile is driven by its low business risk gas transmission and distribution assets that operate in the credit supportive regulatory environment of British Columbia and its monopoly position in its service territory. The company has a long track record of earning its allowed return on equity and its cash flow continues to be highly predictable. These strengths are offset by the company's weak financial metrics that we forecast will be in the range of 11-13% CFO pre-W/C to debt. These financial metrics are primarily a product of a low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates. The credit profile also reflects FEI's independence from lower rated and heavily levered parent company Fortis Inc. (FTS, Baa3 stable) that does not constrain the utility's stand alone credit quality.

Exhibit 1
Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt (CAD$ MM)



Source: Moody's Financial Metrics

Credit strengths

» Low risk gas transmission and distribution business

» Credit supportive regulatory environment

» Predictable and growing cash flow

Credit challenges

» High leverage and weak financial metrics

» Performance based regulation (PBR) marginally increases risk compared to cost of service regulation

» Although independent of FTS, parent is heavily levered

Rating outlook

The stable outlook for FEI is based on our expectation of a continuing supportive regulatory environment and consistent, albeit weak, financial metrics that provide limited cushion at the current rating level.

Factors that could lead to an upgrade

Given the ongoing forecast weakness in credit metrics, an upgrade is unlikely over the near term. We could upgrade the company with a material, sustained improvement in financial metrics, including a ratio of CFO pre W/C to debt in the mid to high teens

Factors that could lead to a downgrade

While we do not expect it, an adverse regulatory decision or a forecast of a sustained deterioration in credit metrics including CFO pre-W/C to debt of less than 11%

Key indicators

Exhibit 2

FortisBC Energy Inc. [1]

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Sept-22
CFO Pre-W/C + Interest / Interest	2.5x	3.0x	2.9x	3.9x	3.1x
CFO Pre-W/C / Debt	13.6%	13.6%	11.3%	12.0%	12.9%
CFO Pre-W/C – Dividends / Debt	8.8%	8.7%	6.6%	7.3%	8.2%
Debt / Capitalization	47.8%	47.5%	48.8%	48.2%	47.6%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

FEI, headquartered in Vancouver, is the largest gas transmission and distribution company in British Columbia serving about 1,069,300 customers, around 91% of which are residential. FEI is regulated by the British Columbia Utilities Commission (BCUC) under performance based regulation (PBR). FEI is a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI, not rated) which, in turn, is wholly owned by FTS, a diversified electric and gas utility holding company. Another FTS subsidiary, FortisBC Inc (Baa1 stable) is a vertically integrated regulated hydro-electric utility that also operates in BC.

Exhibit 3
FBC's and FEI's service area

Source: Fortis Investor Presentation

Detailed credit considerations

Credit supportive regulatory environment

FEI's credit quality continues to be driven by its credit supportive regulatory environment and its monopoly position. The legislative and judicial underpinnings of the regulatory framework are stable and we expect them to remain so, with a strong rule of law and the province providing the legislative framework. Legislation is not prescriptive in terms of rate-setting methodology, although the company has been able to earn its allowed ROE under both Performance Based Regulation and traditional Cost of Service. Both frameworks have been used for establishing tariffs in the past.

Generally, when the utility or other stakeholders materially disagree with some aspects of regulatory decisions, they have been successful in asking the regulator to review and adjust those decisions with final outcomes that have been generally acceptable to all parties as evidenced by a lack of court proceedings. The company is able to challenge regulatory decisions in the courts, although this has not happened since the utility was acquired by FTS in 2007.

Decisions from the regulator tend to be predictable, consistent and transparent with a consultative approach to regulation. The regulatory framework established by the BCUC has a long track record of enabling the company to generate predictable cash flow and earn its allowed returns, supporting our view that regulation is consistent and predictable.

The company has a track record of passing through its commodity costs in rates, has no direct exposure to commodity price risk and negligible volume risk, a credit positive. To the extent that these or other costs deviate from forecasted values, deferral or true up mechanisms limit exposure to forecast differentials. Commodity price risk is addressed through the commodity cost reconciliation account (CCRA) and delivery costs to FEI are recovered through a midstream cost reconciliation account (MCRA). Volume risk is addressed by the revenue stabilization and adjustment mechanism (RSAM) that captures weather related and volume variances for residential and commercial customers. The CCRA is reviewed quarterly and amortized over 12 months. The MCRA and RSAM variances are reviewed annually and amortized over two years. A separate flow through deferral captures other variances, including industrial volume variances, is reviewed annually and amortized over 1 year.

Performance based regulation (PBR) marginally increases risk

PBR marginally increases risk because of the potential for higher cash flow volatility compared to Cost of Service regulation, particularly toward the latter years of the 5 year period. We believe that management will be successful in managing the challenges inherent in its PBR plan and continue to earn the allowed return on equity established by the regulator. In addition, the PBR plan offers downside protection that limits risk to the utility.

Rates had previously been set using performance, or incentive based, regulation for the period 2014-2019. The utility applied for a multiyear ratemaking plan for the period 2020-2024 at the end of the preceding period. A decision on the application was published on June 22, 2020 and we continue to refer to the rate-setting mechanism as PBR. We note that there was regulatory lag with this decision, but the company received interim rates as requested, mitigating this lag.

The company's controllable operating and maintenance (O&M) expenses are established by formula for the 2020-2024 period. We expect the utility to perform broadly in line with the O&M allowances over the period. O&M costs are increased annually by inflation minus a 0.5% productivity factor reducing risk in an inflationary environment. The earning sharing mechanism (ESM) remains unchanged, so any over/underspend is shared with customers in the subsequent year on a 50/50 basis. Non-controllable opex is a flow through to customers. Some other controllable costs are based on forecast and subject to the ESM.

FEI has a strong track record of recovering capital expenditures in rates in a timely fashion, a key credit strength and we expect the utility to recover its capex in the current period. The ESM applies to the WACC, depreciation and tax related to certain types of capex over or underspend during the period. For example, a $10 million underspend in capex that is subject to the ESM would result in half of the WACC, depreciation and tax related amounts associated with the $10 million underspend being subject to the ESM in the next year. This would similarly apply to a $10 million overspend. This represents the only portion of depreciation, interest and income tax variances that are shared with customers, the rest of these amounts are a pass through to customers. The table below shows the different types of capital expenditures, how each type of capex is recovered in rates, the ESM that applies, if any, and key details. We expect the company will likely continue a trend of overspending its growth capex over the current period.

Exhibit 4
Capital expenditures summary

	Recovery in Rates	Under/Overspend	How amounts are determined
Capex - Sustainment	Forecast basis, cash WACC and depreciation	ROE variances driven by actual rate base differences from forecast rate base levels, and ROE variances stemming from interest expense, tax and depreciation, all subject to ESM	Forecast for 2020-2022. 2023-2024 forecast submitted in annual review for 2023 rates. Forecast WACC and depreciation recovered in rates.
Capex - Growth	Formula driven amounts in rates, cash WACC and depreciation	ROE variances driven by actual rate base differences from forecast rate base levels, and ROE variances stemming from interest expense, tax and depreciation, all subject to ESM	Formula relates to prior unit cost of growth capital X inflation -0.5% productivitiy factor *100% of forecast customer additions with a true up for actual customer additions in the next year.
Capex - Major Projects (CPCN)	When project complete	Capex subject to prudency test	CPCN capital is based on project specific forecast. WACC capitalized during construction. Depreciation and cash WACC begins when project complete.
Capex - Other Capital	On a forecast basis, cash WACC and depreciation	Capex subject to prudency test	Smaller items that fall outside the other categories. This is forecast on an annual basis and is subject to a true up and prudency review

Source: BCUC Decision, Orders G-165-20 and G-166-20

The use of forecasts and formulas for the PBR period provides long term visibility of capex allowances and recovery. For capital projects in excess of $15 million, the company requires a certificate of public convenience and necessity (CPCN) that reduces the probability of cost disallowances, a credit positive. The company capitalizes its weighted average cost of capital during construction, which may cause large, multi-year projects to put some downward pressure on financial metrics, a credit negative. The company has not experienced any material cost disallowances.

There are two important components of the PBR plan that limit risk to the utility. Financial off ramps are triggered if, in any one year, FEI's ROE differs by more than 150 bps (post ESM) from the allowed return, up or down. Secondly, the Z-factor is designed to address non-controllable and unforeseen costs that flow through in rates. The materiality threshold for FEI is set at $500,000 which reduces the utility's risk. The company can file a Z-factor application to recover non-controllable and unforeseen costs that exceed the materiality threshold. The annual review process also provides an avenue to review FEI's performance on an annual basis.

Service Quality Indicators (SQI's) are used to monitor utility performance to ensure that any efficiencies or cost reductions do not result in a reduction in the quality of service to customers. The utility has not had any incremental incentives or penalties associated with performance on the SQI's, however a deterioration in performance would likely lead to more challenging regulatory outcomes and increased scrutiny in the future. We believe that FEI's customers, who are primarily residential, continue to have the capacity and willingness to pay their bills.

Predictable and growing cash flow but weak financial metrics

We expect the utility to continue to generate predictable cash flow and financial metrics, a key credit strength. Underpinning this predictability, cash flow from operations is generally a function of the company's rate base, the low allowed equity component in its capital structure (38.5% equity), a relatively low return on equity (8.75%), and depreciation rates. We forecast CFO pre-W/C to debt in the 11-13% range for the next several years, a level that provides limited cushion at its current rating. The utility has a long track record of earning its allowed return on equity and we have assumed that the company will continue to do so. A significant portion of the variability in CFO pre-W/C to debt stems from movements in working capital which represent changes in deferral accounts that are ultimately passed through in rates. This is evidenced by the FFO/debt ratio that has varied by less than 200 bps since 2016 based on fiscal year end results compared to CFO-pre W/C to debt that has been in a range of more than 400 bps over the same period. The financial off ramp at 150 bps (post ESM) and the low threshold on the Z-factor reduce the risk of significant variability in financial performance.

In January 2021, the BCUC announced that it was initiating a generic cost of capital proceeding that will revisit the capital structure and allowed ROE. We have assumed that there will be no changes stemming from this decision that would put downward pressure on financial metrics. We expect a decision in the first half of 2023 and the timing of any changes will be addressed in the decision. We expect the company's dividend policy, net of any equity injections, will continue to maintain the deemed capital structure.

Exhibit 5
Approved ROE, Equity thickness and Rate Base

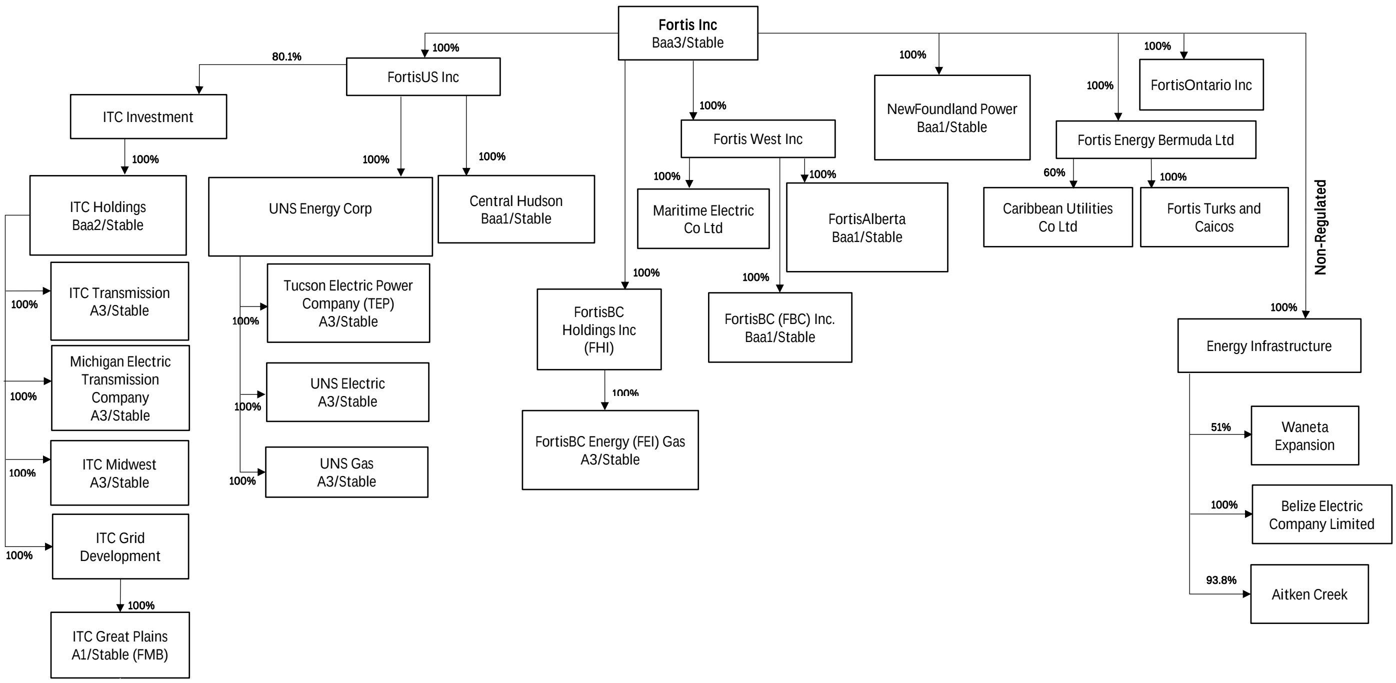
	2017	2018	2019	2020	2021	2022F
ROE	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%
Equity thickness	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
Midyear Rate base, CAD billion	4.1	4.4	4.5	5.1	5.2	5.4

Source: FortisBC Energy

Although independent of Fortis Inc., parent is heavily levered

We consider FEI to be operationally and financially independent of ultimate parent FTS. However, FTS has very high leverage and material holding company debt that adds financial risk across the entire FTS corporate family. FTS is dependent upon its many subsidiaries, including FEI, to make distributions to service its obligations. Despite this leverage, we view FTS ownership as generally credit positive for FEI since it benefits from access to a large and diversified parent that may facilitate streamlining operations and costs and provides strong access to capital markets. The company may periodically rely on its parent for equity injections to maintain its capital structure in line with the regulator's established parameters. We expect that FTS would provide extraordinary support to FEI, if required, provided that the parent had the economic incentive to do so. We believe that the parent will continue to have sufficient resources to provide support, if required. As of 30 September 2022, FTS had about CAD2.0 billion unused committed revolving credit facility at the FTS corporate level. Ring fencing provisions at FEI limit the ability of FTS to upstream cash, although we do not believe the parent would seek to increase leverage above the levels established by the regulator. Our view of parent FTS does not constrain the credit profile of FEI.

Exhibit 6
Fortis Inc's organizational structure



Source: Fortis Inc

ESG considerations

FortisBC Energy Inc.'s ESG Credit Impact Score is Moderately Negative CIS-3

Exhibit 7
ESG Credit Impact Score

CIS-3

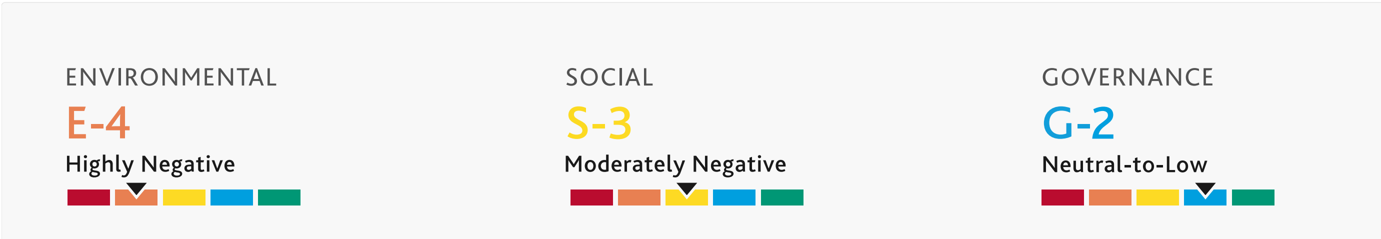
Moderately Negative

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

FEI's ESG Credit Impact Score is moderately negative (**CIS-3**), indicating that its ESG attributes have an overall limited impact on the current rating, with potential for future negative impact over time. The scores reflect high environmental risks, moderate social risks and low governance risks.

Exhibit 8
ESG Issuer Profile Scores



Source: Moody's Investors Service

Environmental

FEI's high environmental risk (**E-4** issuer profile score) reflects its elevated exposure to carbon transition risk given British Columbia's legislated commitments to reduce greenhouse gas emissions by 40% by 2030 and 80% by 2050 and that all of the company's network operations are gas.

Social

Exposure to social risks is moderately negative (**S-3** issuer profile score) reflecting the sector's fundamental risk that demographic and social trends could trigger public affordability concerns that could lead to adverse regulatory or political intervention. FEI, similar to peers, is also moderately exposed to responsible production risk because a gas leak or explosion, although unlikely, could have a significant negative impact on its reputation and financial profile.

Governance

FEI's governance is driven by that of its parent FTS. FEI's governance risk is broadly in line with other utilities and does not pose a particular risk (**G-2** issuer profile score). This is supported by a key financial policy to maintain the capital structure established by the regulator with any dividends paid to the parent offset by sufficient equity injections to maintain the target capital structure. FEI's management credibility and track record also support the low risk governance outcome.

ESG Issuer Profile Scores and Credit Impact Scores for FEI are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for FEI on MDC and view the ESG Scores section.

Liquidity analysis

FEI maintains adequate liquidity. It has a CAD700 million syndicated credit facility maturing in July 2026 that supports a commercial paper program, and a CAD55 million uncommitted letter of credit facility maturing in March 2023. The credit facility contains a material adverse event clause that requires notification to lenders, but does not prohibit new borrowings. The company is currently well below the single debt to total capitalization ratio covenant (maximum 75%) in the credit agreement. At September 30, 2021, CAD383 million was available under this facility.

For the twelve months ended September 2022, FEI reported negative free cash flow of CAD253 million as a result of CAD487 million of CFO, CAD169 million of dividends and CAD571 million of capex. We estimate that annual negative free cash flow will be around CAD300 million in 2022 on the basis of about CAD470 million of CFO, CAD600 million of capex and CAD170 million of annual dividends. We expect FEI to manage dividend payouts and parent equity injections, along with its capex spending and borrowing profile, to maintain an equity layer close to the approved level of 38.5%.

FEI's next debt maturity is CAD150 million of unsecured debentures due in 2026.

Rating methodology and scorecard factors

Exhibit 9
Rating Factors
FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 9/30/2022		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.1x	Baa	3.5x - 4x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	12.4%	Baa	11% - 13%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	7.6%	Baa	6% - 9%	Baa
d) Debt / Capitalization (3 Year Avg)	47.9%	A	46% - 49%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2022(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 10
Peer Comparison Table [1]

	FortisBC Energy Inc. A3 (Stable)			FortisBC Inc. Baa1 (Stable)			FortisAlberta Inc. Baa1 (Stable)			Hydro One Inc. A3 (Stable)		
(In CAD millions)	FYE Dec-20	FYE Dec-21	LTM Sept-22	FYE Dec-20	FYE Dec-21	LTM Sept-22	FYE Dec-20	FYE Dec-21	LTM Sept-22	FYE Dec-20	FYE Dec-21	LTM Sept-22
Revenue	1,385	1,714	1,949	412	454	471	653	708	735	7,250	7,185	7,657
CFO Pre-W/C	389	422	466	107	127	137	394	366	376	1,874	2,039	2,230
Total Debt	3,430	3,511	3,605	1,249	1,267	1,310	2,391	2,409	2,525	15,644	15,010	14,911
CFO Pre-W/C + Interest / Interest	2.9x	3.9x	3.1x	2.5x	2.7x	2.8x	4.8x	4.4x	4.5x	4.5x	4.8x	5.1x
CFO Pre-W/C / Debt	11.3%	12.0%	12.9%	8.6%	10.0%	10.5%	16.5%	15.2%	14.9%	12.0%	13.6%	15.0%
CFO Pre-W/C – Dividends / Debt	6.6%	7.3%	8.2%	5.0%	6.3%	6.7%	13.1%	11.6%	11.2%	8.1%	9.4%	10.6%
Debt / Capitalization	48.8%	48.2%	47.6%	54.3%	53.4%	53.8%	55.4%	54.5%	54.8%	58.9%	56.5%	54.9%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Exhibit 11

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Sept-22
As Adjusted					
FFO	**407**	**417**	**412**	**479**	**491**
+/- Other	-5	7	-23	-57	-25
CFO Pre-WC	**402**	**424**	**389**	**422**	**466**
+/- ΔWC	-46	-13	-48	95	23
CFO	**356**	**411**	**341**	**517**	**489**
- Div	143	151	162	166	169
- Capex	486	483	477	513	609
FCF	**-273**	**-223**	**-298**	**-162**	**-289**
(CFO Pre-W/C) / Debt	13.6%	13.6%	11.3%	12.0%	12.9%
(CFO Pre-W/C - Dividends) / Debt	8.8%	8.7%	6.6%	7.3%	8.2%
FFO / Debt	13.8%	13.4%	12.0%	13.6%	13.6%
RCF / Debt	8.9%	8.5%	7.3%	8.9%	8.9%
Revenue	1,187	1,330	1,385	1,714	1,949
Interest Expense	275	216	209	147	218
Net Income	171	172	180	173	195
Total Assets	6,888	7,351	7,738	8,173	8,514
Total Liabilities	4,168	4,460	4,758	5,076	5,244
Total Equity	2,720	2,891	2,980	3,097	3,270

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 12

FortisBC Energy Inc. Moody's - Adjusted Debt Breakdown

(CAN Millions)	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21	LTM Sept-22
As Reported Debt	**2,578.0**	**2,832.0**	**2,952.0**	**3,269.0**	**3,368.0**	**3,462.0**
Pensions	91.0	83.0	139.0	155.0	133.0	133.0
Operating Leases	19.2	22.4	8.0	6.0	10.0	10.0
Non-Standard Adjustments	19.0	20.0	21.0	0.0	0.0	0.0
Moody's Ajusted Debt	**2,707.2**	**2,957.4**	**3,120.0**	**3,430.0**	**3,511.0**	**3,605.0**

Based on consolidated financial data of FortisBC Energy Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics

Ratings

Exhibit 13

Category	Moody's Rating
FORTISBC ENERGY INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
ULT PARENT: FORTIS INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa3
Senior Unsecured	Baa3

Source: Moody's Investors Service

REPORT NUMBER 1350010

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S INVESTORS SERVICE

FortisBC Energy Inc.
Consolidated Financial Statements
for the years ended
December 31, 2022 and 2021

FortisBC Energy Inc.
An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2022 and 2021

Independent Auditor’s Report

To the Shareholder and the Board of Directors of
FortisBC Energy Inc.

Opinion

We have audited the consolidated financial statements of FortisBC Energy Inc. (the “Corporation”), which comprise the consolidated balance sheets as at December 31, 2022 and 2021, and the consolidated statements of earnings, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies (collectively referred to as the “financial statements”).

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2022 and 2021, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (“US GAAP”).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards (“Canadian GAAS”). Our responsibilities under those standards are further described in the *Auditor’s Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

A key audit matter is a matter that, in our professional judgment, was of most significance in our audit of the consolidated financial statements for the year ended December 31, 2022. This matter was addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on this matter.

Impact of Rate Regulation on the Financial Statements — Refer to Note 2 to the Financial Statements

Key Audit Matter Description

The Corporation is subject to rate regulation and annual earnings oversight by the British Columbia Utilities Commission (“BCUC”). Rates and resultant earnings of the Corporation are determined under performance-based rate-setting mechanism. The regulation of rates is premised on reasonable opportunity to recover prudently incurred costs and an allowed rate of return on common shareholders’ equity (“ROE”). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a key audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation has indicated they expect to recover costs from customers through regulated rates, there is a risk that the BCUC will not approve full recovery of the costs incurred. Auditing these matters required especially subjective judgement and specialized knowledge of accounting for rate regulation due to its inherent complexities.

How the Key Audit Matter was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Evaluating the likelihood of recovery in future rates or of a future reduction in rates by assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information.
- For regulatory matters in process, inspecting the Corporation’s filings and intervenor filings for any evidence that might contradict management’s assertions. We obtained an analysis from management regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

Other Information

Management is responsible for the other information. The other information comprises Management’s Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management’s Discussion and Analysis prior to the date of this auditor’s report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor’s report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our

opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Brenton Francis.

/s/ Deloitte LLP

Chartered Professional Accountants
Vancouver, British Columbia
February 9, 2023

FORTIS BC

FortisBC Energy Inc.
Consolidated Balance Sheets
As at December 31
(in millions of Canadian dollars)

ASSETS		**2022**		2021
Current assets				
Cash	**$**	**43**	$	4
Accounts receivable and other current assets, net (notes 4, 22 and 24)		**580**		344
Inventories (note 5)		**121**		74
Prepaid expenses		**7**		7
Regulatory assets (notes 8 and 22)		**220**		133
Total current assets		**971**		562
Property, plant and equipment, net (note 6)		**5,839**		5,480
Intangible assets, net (note 7)		**126**		123
Regulatory assets (note 8 and 22)		**1,040**		1,080
Other assets (note 9)		**20**		15
Goodwill (note 10)		**913**		913
TOTAL ASSETS	**$**	**8,909**	$	8,173
LIABILITIES AND EQUITY				
Current liabilities				
Credit facilities (notes 23 and 26)	**$**	**203**	$	242
Accounts payable and other current liabilities (notes 11, 22 and 24)		**788**		530
Current portion of finance leases and finance obligation (note 13)		**1**		4
Regulatory liabilities (note 8)		**108**		26
Total current liabilities		**1,100**		802
Long-term debt (notes 12 and 22)		**3,273**		3,123
Finance leases and finance obligation (note 13)		**1**		1
Regulatory liabilities (note 8)		**416**		210
Deferred income tax (note 21)		**668**		674
Other liabilities (notes 14, 16 and 22)		**138**		257
Total liabilities		**5,596**		5,067
Commitments (note 25)				
Equity				
Common shares [1] (note 15)		**1,641**		1,491
Additional paid-in capital		**1,245**		1,245
Retained earnings		**418**		361
Shareholder's equity		**3,304**		3,097
Non-controlling interests		**9**		9
Total equity		**3,313**		3,106
TOTAL LIABILITIES AND EQUITY	**$**	**8,909**	$	8,173

[1] 500 million authorized common shares with no par value; 357.2 million issued and outstanding at December 31, 2022 (December 31, 2021 – 347.4 million).

Approved on behalf of the Board:

(Signed by) Peter Blake
Director

(Signed by) Roger Dall'Antonia
Director

See accompanying notes to these Consolidated Financial Statements.

FORTIS BC

FortisBC Energy Inc.
Consolidated Statements of Earnings
For the years ended December 31
(in millions of Canadian dollars)

	2022	2021
Revenue (note 17)	**$ 2,083**	$ 1,714
Expenses		
Cost of natural gas	**1,055**	713
Operation and maintenance (notes 4 and 24)	**292**	284
Property and other taxes	**72**	71
Depreciation and amortization (notes 6, 7 and 8)	**302**	285
Total expenses	**1,721**	1,353
Operating income	**362**	361
Other income (notes 18 and 24)	**123**	12
Finance charges (notes 19 and 24)	**246**	144
Earnings before income taxes	**239**	229
Income tax expense (note 21)	**11**	46
Net earnings	**228**	183
Net earnings attributable to non-controlling interests	**1**	1
Net earnings attributable to controlling interest	**$ 227**	$ 182

FortisBC Energy Inc.
Consolidated Statements of Changes in Equity
For the years ended December 31
(in millions of Canadian dollars)

	Common Shares *(#millions)*	**Common Shares**	**Additional Paid-in Capital**	**Non-Controlling Interests**	**Retained Earnings**	**Total**
As at December 31, 2020	341.2	$ 1,391	$ 1,245	$ 9	$ 344	$ 2,989
Net earnings	-	-	-	1	182	183
Net distribution to Mt. Hayes Storage LP Partners	-	-	-	(1)	-	(1)
Issuance of common shares	6.2	100	-	-	-	100
Dividends on common shares	-	-	-	-	(165)	(165)
As at December 31, 2021	347.4	$ 1,491	$ 1,245	$ 9	$ 361	$ 3,106
Net earnings	**-**	**-**	**-**	**1**	**227**	**228**
Net distribution to Mt. Hayes Storage LP Partners	**-**	**-**	**-**	**(1)**	**-**	**(1)**
Issuance of common shares	**9.8**	**150**	**-**	**-**	**-**	**150**
Dividends on common shares	**-**	**-**	**-**	**-**	**(170)**	**(170)**
As at December 31, 2022	**357.2**	**$ 1,641**	**$ 1,245**	**$ 9**	**$ 418**	**$ 3,313**

See accompanying notes to these Consolidated Financial Statements.

FortisBC Energy Inc.
Consolidated Statements of Cash Flows
For the years ended December 31
(in millions of Canadian dollars)

	2022	2021
Operating activities		
Net earnings	**$ 228**	$ 183
Adjustments to reconcile net earnings to cash from operating activities:		
Depreciation and amortization (notes 6, 7 and 8)	**302**	285
Accrued employee future benefits	**(2)**	13
Equity component of allowance for funds used during construction (notes 6 and 18)	**(13)**	(7)
Deferred income tax, net of regulatory adjustments (note 21)	**(4)**	16
Amortization of debt issue costs	**1**	1
Change in regulatory assets and liabilities	**155**	(70)
Change in working capital (note 20)	**(55)**	94
Cash from operating activities	**612**	515
Investing activities		
Property, plant and equipment additions (note 20)	**(573)**	(457)
Intangible asset additions	**(16)**	(18)
Contributions in aid of construction	**15**	7
Change in other assets and other liabilities	**(85)**	(82)
Cash used in investing activities	**(659)**	(550)
Financing activities		
Net repayment of credit facility (note 23)	**(39)**	(16)
Proceeds from issuance of long-term debt (note 12)	**150**	150
Debt issuance costs	**(1)**	(2)
Repayment of finance leases and finance obligation (note 13)	**(3)**	(36)
Distributions to non-controlling interests	**(1)**	(1)
Issuance of common shares	**150**	100
Dividends on common shares	**(170)**	(165)
Cash from financing activities	**86**	30
Net change in cash	**39**	(5)
Cash at beginning of year	**4**	9
Cash at end of year	**$ 43**	$ 4

Supplementary Information to Consolidated Statements of Cash Flows (note 20).

See accompanying notes to these Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

FortisBC Energy Inc. ("FEI" or the "Corporation") is a wholly-owned subsidiary of FortisBC Holdings Inc. ("FHI"), which is a wholly-owned subsidiary of Fortis Inc. ("Fortis"). Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

FEI is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 1,075,600 residential, commercial, industrial, and transportation customers through approximately 51,200 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers, and obtains natural gas and renewable gas supplies on behalf of most residential, commercial, and industrial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and are presented in Canadian dollars unless otherwise specified. In management's opinion, the Consolidated Financial Statements include all adjustments that are necessary to present fairly the consolidated financial position of the Corporation.

The Consolidated Financial Statements include the accounts of the Corporation and its subsidiaries and its 85 per cent interest in the Mt. Hayes Storage Limited Partnership ("MHLP"). The Corporation consolidates 100 per cent of its subsidiaries and recognizes 15 per cent of the MHLP as non-controlling interests. All intercompany transactions and balances have been eliminated upon consolidation.

An evaluation of subsequent events through February 9, 2023, the date these Consolidated Financial Statements were issued, was completed to determine whether any circumstances warranted recognition or disclosure of events or transactions in the Consolidated Financial Statements as at December 31, 2022. No subsequent events have been identified for disclosure in these Consolidated Financial Statements.

Regulation

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as rates, construction plans, and financing.

The Corporation's Consolidated Financial Statements have been prepared in accordance with US GAAP, including certain accounting treatments that differ from those for enterprises not subject to rate regulation. The impacts of rate regulation on the Corporation's operations for the years ended December 31, 2022 and 2021 are described in these "Summary of Significant Accounting Policies", note 3 "Regulatory Matters", note 6 "Property, Plant and Equipment", note 7 "Intangible Assets", note 8 "Regulatory Assets and Liabilities", note 16 "Employee Future Benefits", and note 21 "Income Taxes".

When the BCUC issues decisions affecting the financial statements, the effects of the decision are usually recorded in the period in which the decision is received. In the event that a regulatory decision is received after the balance sheet date but before the Consolidated Financial Statements are issued, the facts and circumstances are reviewed to determine whether it is a recognized subsequent event.

Cash

Cash includes cash and short-term deposits with maturities of three months or less from the date of deposit.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Allowance for Credit Losses

The Corporation records an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. The credit loss allowance is estimated based on historical experience, current conditions, reasonable and supportable economic forecasts and accounts receivable aging. In addition to historical collection patterns, the Corporation considers customer class, customer size, economic indicators and certain other risk characteristics when evaluating the credit loss allowance. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

The BCUC has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are probable to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the BCUC could alter the amounts subject to deferral, at which time the change would be reflected in the Consolidated Financial Statements. For regulatory assets and liabilities which are amortized, the amortization is approved by the BCUC. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories of gas in storage represent gas purchases injected into storage and are valued at weighted average cost. The cost of gas in storage is recovered from customers in future rates.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated depreciation and unamortized contributions in aid of construction ("CIAC"). Cost includes all direct expenditures, betterments and replacements and, as prescribed by the BCUC, an allocation of overhead costs and both a debt and an equity component of allowance for funds used during construction ("AFUDC") at approved rates.

Certain additions to property, plant and equipment are made with the assistance of CIACs from customers when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers' specific requirements.

Depreciation is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in property, plant and equipment commencing at the beginning of the year following when the asset is available for use.

As approved by the BCUC, the remaining book value after the removal of property, plant and equipment is charged to accumulated depreciation. It is expected that these amounts charged to accumulated depreciation will be reflected in future depreciation expense when refunded or collected in customer rates.

As approved by the BCUC, removal costs are collected as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible Assets

Intangible assets are comprised of right of ways and software not directly attributable to the operation of property, plant and equipment and are recorded at cost less accumulated amortization. Included in the cost of intangible assets are all direct expenditures, betterments and replacements and, as prescribed by the BCUC, both a debt and equity component of AFUDC at approved rates.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization is based on rates approved by the BCUC and is calculated on a straight-line basis commencing at the beginning of the year following when the asset is available for use.

Intangible assets with indefinite useful lives are not subject to amortization and are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

No impairment provision has been determined for the years ended December 31, 2022 and 2021.

Leases

Leases that transfer to the Corporation substantially all the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

When a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a right-of-use asset and lease liability is recognized on the balance sheet. At inception, the right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components and fixed non-lease components, which the Corporation accounts for as a single lease component.

The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised. Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense straight-line over the lease term.

Finance leases are amortized over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case finance leases are amortized over the estimated service life of the underlying asset. Where the BCUC has approved recovery of the lease payments for rate-setting purposes instead of the depreciation expense and finance charges otherwise recognized for accounting purposes, the depreciation expense related to the lease is modified to conform with the rate-setting process. Therefore, the total depreciation expense and finance charges recognized during a period equals the expense included in allowable costs for rate-making purposes during that period, with the difference recognized as a regulatory asset to be recovered from customers over the term of the related arrangements.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair return on capital or assets, is provided through customer rates approved by the BCUC. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility. There was no impairment of long-lived assets for the years ended December 31, 2022 and 2021.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Impairment testing is performed if any event occurs or if circumstances change that would indicate that the fair value of the Corporation was below its carrying value. If that is the case, goodwill is written down to estimated fair value and an impairment loss is recognized. No such event or changes in circumstances occurred during 2022 or 2021.

Otherwise, the Corporation performs an annual assessment of goodwill which was performed by the Corporation during 2022 and it was concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

Asset Retirement Obligations

The Corporation will recognize the fair value of a future Asset Retirement Obligation ("ARO") as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The fair value of the ARO is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the ARO will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are to be recognized in earnings as an operating expense using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Corporation's natural gas transmission and distribution systems are not currently determinable as they will be used in perpetuity, the Corporation has not recognized an ARO as at December 31, 2022 and 2021. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

Revenue Recognition

Revenue from Contracts with Customers

Natural gas revenue is billed at rates approved by the BCUC and is bundled to include the costs of delivery, commodity and midstream. The delivery component of the rates includes customer service as well as other corporate and service functions.

The majority of the Corporation's revenue is derived from natural gas sales to residential, commercial, industrial, and transportation customers. Most of the Corporation's contracts have a single performance obligation, the delivery of natural gas. Substantially all of the Corporation's performance obligations are satisfied over time as natural gas is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress, gigajoules ("GJ") delivered. The billing of natural gas sales is based on the reading of customer meters, which occurs on a systematic basis throughout the month. Natural gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each reporting date. No component of the transaction price is allocated to unsatisfied performance obligations.

Other contract revenue from customers includes fees charged for utility customer connections, which is recognized as revenue when billed to the customer, and agreements with certain customers to provide transportation of natural gas over utility owned infrastructure, which is recognized as revenue as natural gas is delivered, using an output measure of progress, GJ delivered.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria established by the BCUC are met. The Corporation has identified its Earnings Sharing Mechanism, Revenue Stabilization Adjustment Mechanism, and Flow-through variances related to industrial and other customer revenue as alternative revenue.

The Earnings Sharing Mechanism allows for a 50/50 sharing of variances from allowed Return on Equity ("ROE"), approved as part of the annual revenue requirements. This mechanism is in place until the expiry of the current Multi-Year Rate Plan ("MRP") for 2020 to 2024. In addition, alternative revenue includes variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year in a Revenue Stabilization Adjustment Mechanism, which is either refunded to or recovered from customers in rates within 2 years. Variances in the forecast versus actual customer use rate for industrial and other customer revenue are recognized in a flow-through deferral account to be either refunded to or recovered from customers in the following year.

Other Revenue (Expense)

Other revenue (expense) is primarily comprised of regulatory deferral adjustments resulting primarily from cost recovery variances in regulated forecasts used to set rates for natural gas revenue. As part of the decision received on FEI's MRP application for the years 2020 to 2024 ("MRP Decision"), effective January 1, 2020 and effective through to the end of the MRP term, the Corporation has a flow-through deferral account that captures variances from certain regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.

The Corporation disaggregates revenue by type of customer, as disclosed in note 17. This represents the level of disaggregation used by the Corporation to evaluate performance.

Employee Future Benefits

The Corporation sponsors a number of post-employment benefit plans. These plans include defined benefit, unfunded supplemental, and various other post-employment benefit ("OPEB") plans.

The cost of pensions and OPEBs earned by employees are actuarially determined as an employee accrues service. The Corporation uses the projected benefit pro-rata method based on years of service, management's best estimates of expected returns on plan assets, salary escalation, retirement age, mortality and expected future health-care costs. The discount rate used to value liabilities is based on Corporate AA bond yields with cash flows that match the timing and amount of the expected benefit payments under the plans. The Corporation uses a measurement date of December 31 for all plans.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets is determined using a smoothed value that recognizes investment gains and losses gradually over a 3 year period.

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and the fair value of plan assets that result from changes in assumptions and experience gains and losses, are amortized straight-line over the expected average remaining service life, or the expected average remaining life expectancy, of the employee group covered by the plans. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

The Corporation records the funded or unfunded status of its defined benefit pension plans and OPEB plans on the balance sheet. Unamortized balances relating to past service costs and net actuarial gains and losses have been recognized in regulatory assets and are expected to be recovered from customers in future rates. Subsequent changes to past service costs and net actuarial gains and losses are recognized as an expense, where required by the BCUC, or otherwise as a change in the regulatory asset or liability.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The Corporation capitalizes the eligible portion of the current service cost component of net benefit cost. The remaining portion of current service cost not capitalized is grouped in the Consolidated Statements of Earnings with other employee compensation costs arising from services rendered. The non-service cost components of net benefit cost are presented in other income.

Fair Value

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The fair values of the Corporation's financial instruments reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except those which qualify for the normal purchases and normal sales exception.

Derivative Financial Instruments

The Corporation uses physical and financial derivative instruments, including natural gas supply contracts and financial swaps, to reduce exposure to natural gas price volatility. None of the derivative instruments were designated as qualifying accounting hedges, but rather serve as economic hedges.

For derivative instruments, any unrealized gains or losses, to the extent that they are refundable or recoverable through regulated rates, associated with the change in fair value of these contracts, and realized losses or gains associated with the settlement of these contracts, are deferred as a regulatory asset or regulatory liability. Had the BCUC not allowed the deferral of unrealized losses or gains resulting from these hedging activities as regulatory assets or liabilities, the Corporation would either designate these contracts as a qualifying cash flow hedge and, to the extent that the cash flow hedges are effective, the unrealized losses or gains would be recognized in accumulated other comprehensive income, net of taxes, or resulting gains and losses would be recorded in the Consolidated Statements of Earnings.

Derivative contracts under master netting agreements and collateral positions are presented on a gross basis.

Debt Issuance Costs

Costs incurred to arrange debt financing are recognized as a direct deduction from the carrying amount of the debt liability and are accounted for using the effective interest method over the life of the related financial liability. Costs incurred to arrange credit facilities are recognized as other assets and amortized over the term of the facility on a straight-line basis.

Sales Taxes

In the course of its operations, the Corporation collects sales taxes from its customers. When customers are billed, a current liability is recognized for the sales taxes included on the customer's bill. This liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes the sales taxes.

Income Taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not (greater than a 50 per cent chance) to be realized.

The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that will be in effect when the temporary differences are expected to be recovered or settled. As a result of rate regulation, deferred income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory asset and liability accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that is expected to be collected in rates once the amount becomes payable.

Any difference between the expense recognized and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment as described in note 8 "Regulatory Assets and Liabilities".

The Corporation recognizes a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50 per cent likely to be realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Interest and penalties related to unrecognized tax benefits are recognized in income tax expense.

Segment Reporting

The Corporation has a single reportable segment.

Use of Accounting Estimates

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, regulatory decisions, current conditions and various other assumptions believed to be reasonable under the circumstances. The use of estimates is described in the "Summary of Significant Accounting Policies", note 8 "Regulatory Assets and Liabilities" and note 25 "Commitments". Certain estimates are also necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

New Accounting Policies

FEI considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board ("FASB"). During the year ended December 31, 2022, there were no ASUs issued by FASB that have a material impact on these Consolidated Financial Statements.

Future Accounting Pronouncements

Any ASUs issued by FASB that are not included in these Consolidated Financial Statements were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on these Consolidated Financial Statements.

3. REGULATORY MATTERS

Decision on Multi-Year Rate Plan for 2020 to 2024

In June 2020, the BCUC issued its decision on FEI's MRP application for the years 2020 to 2024. The approved MRP includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustainment capital, an innovation fund recognizing the need to accelerate investment in clean energy innovation, a number of service quality indicators designed to ensure the Corporation maintains service levels, and a 50/50 sharing between customers and the Corporation of variances from the allowed ROE.

Variances from the allowed ROE subject to sharing include certain components of other revenue and operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, while variances associated with revenues and other expenses, including those that are not controllable or associated with clean growth capital expenditures, are subject to flow-through treatment and refunded to or recovered from customers.

In December 2021, the BCUC approved a delivery rate increase of 8.07 per cent over 2021 rates, effective January 1, 2022. As part of this filing, a 2022 average rate base of $5,409 million was approved.

4. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

The timing of revenue recognition, billings, and cash collections results in billed and unbilled accounts receivable. The opening and closing balances of the Corporation's accounts receivable as at December 31 were as follows:

($ millions)	**2022**	2021
Accrued unbilled revenue from contracts with customers	**271**	200
Billed accounts receivable from contracts with customers	**161**	112
Gas cost mitigation receivables [1]	**72**	15
Fair value of derivative instruments (note 22)	**47**	4
Cash collateral posted (note 22)	**28**	7
Receivables for third party services and other assets [1]	**10**	14
Amounts due from related parties (note 24)	**-**	1
Allowance for credit losses	**(9)**	(9)
Total accounts receivable and other current assets	**580**	344

[1] Representative of receivables not related to contracts with customers.

Accounts receivable are recorded net of an allowance for credit losses. The credit loss allowance recorded for the year ended December 31, 2022 considered current and forecasted economic conditions.

The change in the allowance for credit losses balance is as follows:

($ millions)	**2022**	2021
Beginning of year	**(9)**	(14)
Credit losses expensed	**(3)**	(2)
Credit losses deferred (note 8)	**-**	4
Write-offs, net of recoveries	**3**	3
End of year	**(9)**	(9)

5. INVENTORIES

($ millions)	**2022**	2021
Gas in storage	**117**	71
Materials and supplies	**4**	3
Total inventories	**121**	74

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2022	**Cost**	**Accumulated Depreciation**	**Book Value**	**Weighted Average Depreciation Rate**
($ millions)				
Natural gas transmission systems	**2,049**	**(666)**	**1,383**	**2.0%**
Natural gas distribution systems	**4,755**	**(1,502)**	**3,253**	**2.4%**
Liquefied natural gas plant and equipment	**792**	**(154)**	**638**	**2.4%**
Plant, buildings and equipment	**402**	**(162)**	**240**	**7.0%**
Land	**72**	**-**	**72**	**-**
Assets under construction	**253**	**-**	**253**	**-**
Total property, plant and equipment	**8,323**	**(2,484)**	**5,839**	

December 31, 2021	Cost	Accumulated Depreciation	Book Value	Weighted Average Depreciation Rate
($ millions)				
Natural gas transmission systems	1,918	(638)	1,280	2.0%
Natural gas distribution systems	4,386	(1,407)	2,979	2.4%
Liquefied natural gas plant and equipment	785	(137)	648	2.4%
Plant, buildings and equipment	392	(153)	239	6.9%
Land	72	-	72	-
Assets under construction	262	-	262	-
Total property, plant and equipment	7,815	(2,335)	5,480	

As allowed by the BCUC, during the year ended December 31, 2022 the Corporation capitalized a debt component of AFUDC of $8 million (December 31, 2021 - $4 million) and an equity component of AFUDC of $13 million (December 31, 2021 - $7 million), and approved capitalized overhead costs of $53 million (December 31, 2021 - $53 million).

Depreciation of property, plant and equipment, including a net salvage provision, for the year ended December 31, 2022 totaled $246 million (December 31, 2021 - $238 million).

Included in the book value of plant, buildings and equipment are vehicle and equipment finance leases of $2 million (December 31, 2021 - $2 million).

7. INTANGIBLE ASSETS

December 31, 2022	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Software	**99**	**(35)**	**64**
Land rights	**59**	**-**	**59**
Other	**3**	**(2)**	**1**
Assets under construction	**2**	**-**	**2**
Total intangible assets	**163**	**(37)**	**126**

December 31, 2021	Cost	Accumulated Amortization	Book Value
($ millions)			
Software	91	(39)	52
Land rights	59	-	59
Other	4	(3)	1
Assets under construction	11	-	11
Total intangible assets	165	(42)	123

There was no impairment of intangible assets for the years ended December 31, 2022 and 2021.

Amortization of intangible assets for the year ended December 31, 2022 totaled $14 million (December 31, 2021 - $13 million).

Amortization of software is recorded on a straight-line basis using an average amortization rate of 14.3 per cent (2021 – 14.5 per cent). Amortization of other intangible assets is recorded on a straight-line basis using an average amortization rate of 1.5 per cent (2021 – 1.5 per cent).

Included in the cost of land rights at December 31, 2022 was $59 million (December 31, 2021 - $59 million) not subject to amortization.

The following is the estimated amortization expense for each of the next five years:

($ millions)	
2023	**14**
2024	**13**
2025	**11**
2026	**9**
2027	**7**

8. REGULATORY ASSETS AND LIABILITIES

Based on existing regulatory orders or the expectation of future regulatory orders, the Corporation has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers as at December 31:

($ millions)	**2022**	2021	**Remaining Refundable Period (Years)**
Regulatory assets			
Regulated asset for deferred income taxes (i)	**669**	671	Ongoing
Demand side management program (ii)	**301**	254	10
Pension and OPEB unrecognized actuarial losses and past service costs (note 16) (iii)	**-**	107	Ongoing
Fair value of derivative instruments[1] (note 22) (iv)	**60**	-	Ongoing
Rate stabilization accounts (v)	**60**	51	1-2
Biomethane variances (vi)	**33**	11	1
Business development deposit[1] (vii)	**30**	18	Ongoing
Greenhouse gas reductions regulation incentives (viii)	**24**	32	10
Flow-through variances (ix)	**20**	15	1
Income taxes recoverable on OPEBs (x)	**18**	18	Ongoing
Deferred development costs for capital projects (xi)	**15**	17	8
Pension and OPEB cost variance (xii)	**14**	3	3
Book value after removal of utility capital assets (xiii)	**5**	9	2
Deferred interest (xiv)	**2**	-	1-3
Other recoverable costs (xv)	**9**	7	Various
Total regulatory assets	**1,260**	1,213	
Less: current portion	**220**	133	
Long-term portion of regulatory assets	**1,040**	1,080	

[1] Balance included in other recoverable costs for the year ended December 31, 2021.

($ millions)	**2022**	2021	**Remaining Refundable Period (Years)**
Regulatory liabilities			
Net salvage provision (xvi)	**219**	181	Ongoing
Rate stabilization accounts (v)	**201**	40	1-2
Pension and OPEB unrecognized actuarial gains and past service costs (note 16) (iii)	**61**	-	Ongoing
Emissions regulations (xvii)	**27**	3	1
Clean growth innovation fund (xviii)	**7**	4	2
Earnings Sharing Mechanism (xix)	**4**	2	1
Deferred interest (xiv)	**3**	2	1-3
Other refundable costs (xv)	**2**	4	Various
Total regulatory liabilities	**524**	236	
Less: current portion	**108**	26	
Long-term portion of regulatory liabilities	**416**	210	

Net amortization expense of regulatory assets and liabilities, excluding a net salvage provision, for the year ended December 31, 2022 totaled $42 million (December 31, 2021 - $34 million).

8. REGULATORY ASSETS AND LIABILITIES (continued)

(i) Regulated Asset for Deferred Income Taxes

FEI recognizes deferred income tax assets and liabilities, and related regulatory liabilities and assets, for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates.

The regulatory asset balance is expected to be recovered from customers in future rates when the deferred taxes become payable.

(ii) Demand Side Management Program

The Corporation funds incentives and provides energy management services to promote efficiency programs for its customers. As approved by the BCUC, the Corporation recovers these costs in rates over a 10-year period.

(iii) Pension and OPEB Unrecognized Actuarial Losses or Gains and Past Service Costs

The net funded status, being the difference between the fair value of plan assets and the projected benefit obligation for pensions and OPEBs, is required to be recognized on the Corporation's balance sheet under ASC Topic 715, *Compensation - Retirement Benefits*. The amount required to make this net funded status adjustment, which would otherwise be recognized in Accumulated Other Comprehensive Income ("AOCI"), has instead been deferred as a regulatory asset or liability. The regulatory asset or liability balance represents the deferred portion of the actuarial gains or losses relating to pensions and OPEBs that is expected to be refunded to or recovered from customers in future rates, as the deferred amounts are included as a component of future net benefit cost.

(iv) Fair Value of Derivative Instruments

Unrealized gains or losses associated with changes in the fair value of certain derivative instruments are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings. This regulatory asset balance is not subject to a regulatory return.

(v) Rate Stabilization Accounts

There are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the impacts of weather and other changes on use rates.

The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred and amounts recovered through rates. Balances to be either refunded to or recovered from customers are determined via quarterly application and review by the BCUC. Currently under this mechanism, there are two separate deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA").

The second mechanism seeks to stabilize delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

The RSAM, MCRA and CCRA accounts are either refunded to or recovered from customers in rates within 2 years with actual refunds or recoveries dependent upon approved rates and actual gas consumption volumes.

8. REGULATORY ASSETS AND LIABILITIES (continued)

The classification of the rate stabilization accounts as at December 31 are as follows:

($ millions)	**2022**	2021
Current assets		
CCRA	**30**	50
RSAM	**-**	1
Total current assets	**30**	51
Long-term assets		
CCRA	**30**	-
Total long-term assets	**30**	-
Total assets	**60**	51
Current liabilities		
MCRA	**(59)**	(22)
RSAM	**(21)**	-
Total current liabilities	**(80)**	(22)
Long-term liabilities		
MCRA	**(92)**	(7)
RSAM	**(29)**	(11)
Total long-term liabilities	**(121)**	(18)
Total liabilities	**(201)**	(40)

(vi) Biomethane Variances

Captures the differences between the costs incurred to procure and process consumable Biomethane gas, including any unsold biomethane inventory, and the revenues collected through the Biomethane energy recovery component of rates, with the difference either refunded to or recovered from customers in rates within one year, with actual refunds or recoveries dependent upon approved rates and actual gas consumption volumes.

(vii) Business Development Deposit

This account relates to the recognition of temporary tax impacts associated with the receipt of deposits on future development expenditures to be incurred for the Eagle Mountain Woodfibre Gas Pipeline project. This regulatory asset balance is not subject to a regulatory return.

(viii) Greenhouse Gas Reductions Regulation Incentives

The Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") incentives deferral is comprised of expenditures to support the growth and development of Compressed Natural Gas and Liquefied Natural Gas markets. The regulatory deferral includes subsidy payments made available to assist customers to purchase natural gas vehicles in lieu of vehicles fueled by diesel, switch to natural gas from diesel for power generation, upgrade equipment to be able to maintain the natural gas equipment and perform feasibility studies and administer the program, all as part of the incentive program funding pursuant to the GGRR under the Clean Energy Act. The BCUC has approved recovery of these costs in rates over a 10-year period.

(ix) Flow-through Variances

As part of the MRP Decision and effective January 1, 2020, the Corporation has a flow-through deferral account that captures certain variances from regulated forecast revenues and other expenses, including those that are not controllable or associated with clean growth expenditures, and that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year. The flow-through regulatory asset includes the current year's flow-through variance and the over or under amortization of prior years' flow-through variances.

8. REGULATORY ASSETS AND LIABILITIES (continued)

(x) Income Taxes Recoverable on OPEBs

The BCUC allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than a cash basis, which creates timing differences for income tax purposes. As approved by the BCUC, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. This regulatory asset balance is expected to be recovered from customers in future rates.

(xi) Deferred Development Costs for Capital Projects

Deferred development costs for capital projects include costs for projects under development that are included in regulated rate base or are anticipated to be recorded in regulated rate base in the future. The BCUC has approved the recovery of certain development costs in rates over a 5 to 20-year period, while the recovery of other development costs is still subject to regulatory review and approval of disposition.

(xii) Pension and OPEB Cost Variance

As approved by the BCUC, the pension and OPEB cost variance account accumulates differences between pension and OPEB expenses that are approved for recovery in rates and the actuarially determined pension and OPEB expense. The BCUC approved the recovery or refund of these variances in rates over a 3-year period.

(xiii) Book Value After Removal of Utility Capital Assets

The remaining book value after the removal of utility capital assets (property, plant and equipment) is a regulatory deferral account that accumulated such balances for 2010 to 2013 and subsequently recovered them from customers through amortization of regulatory assets. In 2014, the BCUC approved the recovery of these costs in rates over a 10-year period.

Subsequent to 2014, FEI records the book value after the removal of property, plant and equipment and intangible assets to accumulated depreciation, which will be reflected in future depreciation expense when refunded or collected in rates.

(xiv) Deferred Interest

The deferred interest is the interest calculated on the difference between the actual and forecasted average balance of the rate stabilization accounts and gas in storage multiplied by the composite interest rate. Amounts are returned to, or recovered from, customers over the same period as the underlying rate stabilization accounts and over 3 years for the gas in storage deferred interest.

(xv) Other Recoverable and Refundable Costs

Regulatory assets and liabilities that have been aggregated in the tables above as other items relate to smaller deferral accounts. These accounts have either been approved by the BCUC for recovery from or refund to customers or are expected to be approved. The approved amounts are being amortized over various periods depending on the nature of the costs. Included in other recoverable costs is the COVID-19 Customer Recovery Fund deferral account, which captures the otherwise uncollectible revenues associated with providing certain deferral and relief offerings to the Corporation’s customers during the COVID-19 pandemic.

(xvi) Net Salvage Provision

The net salvage provision account captures the provision for costs which will be incurred to remove assets from service either through actual removal of the asset or through disconnection from the transmission or distribution system. As actual removal costs are incurred, the net salvage provision account is drawn down. For the year ended December 31, 2022, approximately $57 million (December 31, 2021 - $55 million) was collected from customers through depreciation expense to offset future removal costs which may be incurred. Actual removal costs incurred for the year ended December 31, 2022 were $19 million (December 31, 2021 - $20 million).

8. REGULATORY ASSETS AND LIABILITIES (continued)

(xvii) Emissions Regulations

As approved by the BCUC, the emissions regulations deferral account captures revenues collected from the sale of credits related to Emissions Regulations, particularly the BC Low Carbon Fuel Standard, which are aimed to reduce Greenhouse Gas ("GHG") emissions in BC, and any compliance costs associated with the revenue collection. The BCUC approved the refund of these revenues in rates over a 1-year period effective 2023. Previously this deferral account was approved to be refunded to customers in rates over a 5-year period.

(xviii) Clean Growth Innovation Fund

As approved by the BCUC, the Clean Growth Innovation Fund deferral account was established to explore clean energy innovation activities in an effort to reduce emissions and support the transition to a lower carbon future. This account captures the amounts collected from customers through rates during the MRP period offset by the costs incurred for the purposes of clean growth initiatives.

(xix) Earnings Sharing Mechanism

The Earnings Sharing Mechanism deferral account captures the customer portion of the sharing of variances from the allowed ROE under the MRP Decision. The BCUC has approved the refund or recovery of these variances in customer rates in the following year.

9. OTHER ASSETS

($ millions)	**2022**	2021
Pension assets (note 16)	**8**	4
Operating leases (note 13)	**6**	8
Credit facility issuance costs	**1**	1
Other assets	**5**	2
Total other assets	**20**	15

10. GOODWILL

On May 17, 2007, Fortis acquired all of the issued and outstanding shares of FHI. The consideration paid for this acquisition has been recorded in the Corporation's financial statements using push-down accounting. In addition to goodwill of $913 million (December 31, 2021 - $913 million) for the excess of the purchase price paid by Fortis over the fair value of the net assets acquired, the Corporation has recognized additional paid-in capital related to the push-down of the acquisition accounting.

There was no impairment of goodwill for the years ended December 31, 2022 and 2021.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2022**	2021
Gas cost payable	**157**	120
Trade accounts payable	**134**	106
Business development deposit	**111**	66
Other taxes payable	**86**	65
Fair value of derivative instruments (note 22)	**70**	4
Customer deposits	**63**	54
Employee compensation and benefits payable	**49**	46
Income taxes payable	**45**	9
Interest payable	**38**	37
Other current liabilities	**23**	10
Amounts due to related parties (note 24)	**6**	7
Pension and OPEB liabilities (note 16)	**4**	4
Operating leases (note 13)	**2**	2
Total accounts payable and other current liabilities	**788**	530

12. LONG-TERM DEBT

($ millions)	**2022**	2021
Unsecured Debentures		
6.95% Series 11, due September 21, 2029	**150**	150
6.50% Series 18, due May 1, 2034	**150**	150
5.90% Series 19, due February 26, 2035	**150**	150
5.55% Series 21, due September 25, 2036	**120**	120
6.00% Series 22, due October 2, 2037	**250**	250
5.80% Series 23, due May 13, 2038	**250**	250
6.55% Series 24, due February 24, 2039	**100**	100
4.25% Series 25, due December 9, 2041	**100**	100
3.38% Series 26, due April 13, 2045	**150**	150
2.58% Series 27, due April 8, 2026	**150**	150
3.67% Series 28, due April 9, 2046	**150**	150
3.78% Series 29, due March 6, 2047	**150**	150
3.69% Series 30, due October 30, 2047	**175**	175
6.05% Series 2008, due February 15, 2038	**250**	250
5.20% Series 2010, due December 6, 2040	**100**	100
3.85% Series 31, due December 7, 2048	**200**	200
2.82% Series 32, due August 9, 2049	**200**	200
2.54% Series 33 under Green Bond Framework, due July 13, 2050	**200**	200
2.42% Series 34, due July 18, 2031	**150**	150
4.67% Series 35 under Green Bond Framework, due November 28, 2052	**150**	-
Total long-term debt	**3,295**	3,145
Less: debt issuance costs	**22**	22
Total long-term debt, net of debt issuance costs	**3,273**	3,123

Unsecured Debentures

On November 16, 2022, the Corporation filed a short form base shelf prospectus to establish a Medium Term Note ("MTN") Debentures Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may, from time to time during the 25-month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $800 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

12. LONG-TERM DEBT (continued)

On November 23, 2022, FEI entered into an agreement to issue $150 million of MTN Debentures Series 35. The issuance is the second under FEI's Green Bond Framework, the first of which was in 2020. Net proceeds have been used to finance or refinance eligible projects under FEI's Green Bond Framework and were primarily allocated to energy efficiency, pollution prevention and control, and renewable natural gas categories. These MTN Debentures bear interest at a rate of 4.67 per cent to be paid semi-annually and mature on November 28, 2052. The closing of the issuance occurred on November 28, 2022.

As at December 31, 2022, $650 million remains available under the MTN Debenture Program.

All of the Corporation's debentures are redeemable, in whole or in part, at the option of the Corporation, at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption.

Certain of the Corporation's long-term debt obligations have issuance tests that prevent the Corporation from incurring additional long-term debt that include interest coverage ratios. In addition, the Corporation's credit facility agreements require maintenance of certain financial covenants such as a maximum percentage of debt to equity. As at December 31, 2022 and 2021, the Corporation was in compliance with these covenants.

See note 25 "Commitments" for required principal and interest payments for long-term debt over the next five years and thereafter.

13. LEASES

Finance Obligation

Between 2000 and 2005, the Corporation entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation from the municipalities. The natural gas distribution assets are not accounted for as a sale-leaseback, and instead are accounted for as financing transactions. The proceeds from these transactions have been recorded as finance obligations. Lease payments made, less the portion considered to be interest expense, decrease the finance obligations. In October 2022, the Corporation exercised an early termination payment option in the amount of $3 million on the last remaining financing obligation.

Finance Leases

FEI has finance leases related to vehicles and equipment.

Operating Leases

The Corporation leases office facilities with remaining terms of 1 to 15 years. Most leases include renewal options with renewal terms that may extend the lease term from 1 to 15 years. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the lease premises.

13. LEASES (continued)

The following table details supplemental balance sheet information related to the Corporation's leases for the year ended December 31:

($ millions)	**Classification**	**2022**	2021
Assets			
Long-term			
Operating leases	Other assets (note 9)	**6**	8
Finance leases	Property, plant and equipment, net (note 6)	**2**	2
Total lease assets		**8**	10
Liabilities			
Current			
Operating leases	Accounts payable and other current liabilities (note 11)	**2**	2
Finance leases	Current portion of finance leases and finance obligation	**1**	1
Long-term			
Operating leases	Other liabilities (note 14)	**4**	6
Finance leases	Finance leases and finance obligation	**1**	1
Total lease liabilities		**8**	10

The following table presents the components of the Corporation's lease cost for the year ended December 31:

($ millions)	**2022**	2021
Operating lease cost	**2**	2

As at December 31, 2022, the present value of the future cash flows required over the next five years and thereafter are as follows:

($ millions)	**Operating Leases**	**Finance Leases**	**Total**
2023	**2**	**1**	**3**
2024	**2**	**1**	**3**
2025	**1**	**-**	**1**
2026	**1**	**-**	**1**
2027	**-**	**-**	**-**
Thereafter	**-**	**-**	**-**
Total operating and finance leases	**6**	**2**	**8**
Less: current portion	**2**	**1**	**3**
Long-term portion	**4**	**1**	**5**

13. LEASES (continued)

The Corporation provides the following supplemental information related to its leases for the years ended December 31:

Lease Term and Discount Rate	**2022**	2021
Weighted-average remaining lease term (years)		
Operating leases	**4**	4
Finance leases	**2**	2
Weighted-average discount rate (%)		
Operating leases	**2.8%**	2.7%
Finance leases	**3.1%**	3.0%

Other Information	**2022**	2021
($ millions)		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	**(2)**	(2)
Supplementary non-cash information		
Right-of-use assets obtained in exchange for lease liabilities	**-**	6

In addition, the Corporation leases limited office facilities to others with remaining terms of 1 to 5 years. Most leases include one or more options to renew, with renewal terms that may extend the lease term for 5 to 10 years. These leases are classified as operating leases and income received is recorded to other revenue. Lease revenue received for the year ended December 31, 2022, and lease payments to be received over the next five years and thereafter, are not material to these Consolidated Financial Statements.

14. OTHER LIABILITIES

($ millions)	**2022**	2021
Pension and OPEB liabilities (note 16)	**97**	249
Fair value of derivatives instruments (note 22)	**37**	-
Operating leases (note 13)	**4**	6
Other liabilities	**-**	2
Total other liabilities	**138**	257

15. SHARE CAPITAL

Authorized Share Capital

The Corporation is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Common Shares

Issued and outstanding common shares are as follows:

	2022		2021	
	Number of Shares	**Amount *($ millions)***	Number of Shares	Amount *($ millions)*
Outstanding, beginning of year	**347,369,254**	**1,491**	341,154,514	1,391
Issued	**9,842,755**	**150**	6,214,740	100
Outstanding, end of year	**357,212,009**	**1,641**	347,369,254	1,491

16. EMPLOYEE FUTURE BENEFITS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans and supplemental unfunded arrangements. In addition to pensions, the Corporation also provides OPEBs, other than pensions for retired employees. The following is a summary of each type of plan.

Defined Benefit Pension Plans

The Corporation sponsors a number of defined benefit pension plans. Additionally, the Corporation has a number of closed plans which relate to service prior to 2007 by certain employees. Retirement benefits are based on employees' years of credited service and remuneration. Corporation contributions to the plans are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were as at December 31, 2019 and 2021. The dates of the next required valuations as at December 31, 2022 and 2024, will be completed in 2023 and 2025, respectively.

Supplemental Plans

Certain employees are eligible to receive supplemental benefits. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and certain plans are secured by letters of credit (note 23).

Other Post-Employment Benefits

The Corporation provides retired employees with OPEBs that include, depending on circumstances, supplemental health, dental and life insurance coverage. OPEBs are unfunded and the annual net benefit cost is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, healthcare cost escalation. The date of the next required valuation will be as at December 31, 2024.

16. EMPLOYEE FUTURE BENEFITS (continued)

The financial positions of the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows as at December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Change in fair value of plan assets				
Balance, beginning of year	**832**	756	**-**	-
Actual (loss) return on plan assets	**(74)**	73	**-**	-
Employer contributions	**15**	15	**2**	2
Employee contributions	**13**	13	**-**	-
Benefits paid	**(28)**	(25)	**(2)**	(2)
Fair value, end of year	**758**	832	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**961**	905	**120**	134
Employee contributions	**13**	13	**-**	-
Current service cost	**33**	33	**4**	4
Interest costs	**29**	25	**4**	4
Benefits paid	**(28)**	(25)	**(2)**	(2)
Actuarial (gain) loss	**(243)**	10	**(40)**	(20)
Balance, end of year [1]	**765**	961	**86**	120
Unfunded status	**(7)**	(129)	**(86)**	(120)

[1] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $670 million (December 31, 2021 - $853 million).

The following table summarizes the employee future benefit assets and liabilities and their classification in the Consolidated Balance Sheets as at December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Other assets (note 9)	**(8)**	(4)	**-**	-
Accounts payable and other current liabilities (note 11)	**1**	1	**3**	3
Other liabilities (note 14)	**14**	132	**83**	117
Net liability	**7**	129	**86**	120

16. EMPLOYEE FUTURE BENEFITS (continued)

The net benefit cost for the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows for the years ended December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Service costs	**33**	33	**4**	4
Interest costs	**29**	25	**4**	4
Expected return on plan assets	**(45)**	(41)	**-**	-
Amortization of actuarial losses	**4**	9	**-**	-
Amortization of past service costs	**(1)**	(1)	**-**	-
Regulatory adjustment	**(9)**	(1)	**-**	-
Net benefit cost	**11**	24	**8**	8

The components of net benefit cost, other than the service cost component, are included in other income in the Consolidated Statements of Earnings for the years ended December 31, 2022 and 2021.

Defined Benefit Pension Plan Assets

The assets of the Corporation's funded defined benefit pension plans were invested on a weighted average as follows as at December 31:

	Target Allocation	2022	2021
Equities	**0-60%**	**41%**	39%
Fixed income	**30-100%**	**36%**	40%
Real estate and infrastructure	**0-30%**	**22%**	18%
Private equity	**0-5%**	**1%**	3%
		100%	100%

The investment policy for defined benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Corporation's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost effective manner while not compromising the security of the respective plans. The pension plans use quarterly rebalancing in order to achieve the target allocations while complying with the constraints of the *Pension Benefits Standards Act* of British Columbia and the *Income Tax Act*. The pension plans utilize external investment managers to execute the investment policy. Assets in the plans are held in trust by independent third parties. The pension plans do not directly hold any shares of the Corporation's parent or affiliated companies.

The fair value measurements of the Corporation's defined benefit pension plan assets by fair value hierarchy level, which are described further in note 22, "Financial Instruments", are as follows as at December 31:

2022	**Level 1**	**Level 2**	**Level 3**	**Total**
($ millions)				
Cash	**2**	**-**	**-**	**2**
Equities	**306**	**-**	**-**	**306**
Fixed income	**-**	**269**	**-**	**269**
Real estate and infrastructure	**-**	**-**	**170**	**170**
Private equity	**-**	**-**	**11**	**11**
	308	**269**	**181**	**758**

16. EMPLOYEE FUTURE BENEFITS (continued)

2021	Level 1	Level 2	Level 3	Total
($ millions)				
Cash	3	-	-	3
Equities	340	-	-	340
Fixed income	-	327	-	327
Real estate and infrastructure	-	-	150	150
Private equity	-	-	12	12
	343	327	162	832

The following table is a reconciliation of changes in the fair value of defined benefit pension plan assets that have been measured using Level 3 inputs for the years ended December 31:

($ millions)	**2022**	2021
Balance, beginning of year	**162**	143
Actual return on plan assets relating to assets still held at the reporting date	**20**	18
Purchases, sales and settlements	**(1)**	1
Balance, end of year	**181**	162

Significant Actuarial Assumptions

The significant weighted average actuarial assumptions used to determine the projected benefit obligation and the net benefit cost are as follows:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
	2022	2021	**2022**	2021
Projected benefit obligation				
Discount rate as at December 31	**5.25%**	3.00%	**5.25%**	3.00%
Rate of compensation increases	**3.00%**	3.00%	**-**	-
Net benefit cost				
Discount rate as at January 1	**3.00%**	2.75%	**3.00%**	2.75%
Expected rate of return on plan assets	**6.50%**	5.70%	**-**	-
Health care cost trend rate as at December 31[1]	**-**	-	**5.00%**	5.00%

[1] Ultimate health care cost trend rate was reached in 2018.

16. EMPLOYEE FUTURE BENEFITS (continued)

The following table provides the components and the changes of the regulatory asset during the year that would otherwise have been recognized in other comprehensive income and AOCI and have not yet been recognized as components of periodic net benefit cost. The Corporation's total unrecognized actuarial losses and past service costs for pension and OPEB that was recognized as a regulatory liability as at December 31, 2022 was $61 million (a regulatory asset as at December 31, 2021 - $107 million).

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2022**	2021	**2022**	2021
Regulatory asset (liability), beginning of year	**117**	147	**(10)**	10
Net actuarial gains	**(125)**	(22)	**(40)**	(20)
Amortization of actuarial losses	**(4)**	(9)	**-**	-
Amortization of past service costs	**1**	1	**-**	-
Regulatory (liability) asset, end of year (note 8)	**(11)**	117	**(50)**	(10)

Funding Contributions

Under the terms of the defined benefit pension plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The Corporation's estimated 2023 contributions are $14 million (2022 - $15 million) for defined benefit pension plans and $3 million (2022 - $3 million) for OPEB plans.

Benefit Payments

The following table provides the amount of benefit payments expected to be made over the next 10 years:

($ millions)	**Defined Benefit Pension and Supplemental Plans**	**OPEB Plans**
2023	**33**	**3**
2024	**37**	**3**
2025	**40**	**4**
2026	**43**	**4**
2027	**45**	**4**
2028-2032	**257**	**25**
Total	**455**	**43**

17. REVENUE

Disaggregation of Revenue

The following table presents the disaggregation of the Corporation's revenue by type of customer for the years ended December 31:

($ millions)	**2022**	2021
Residential	**1,182**	941
Commercial	**668**	500
Industrial	**147**	110
Transportation	**82**	94
Total natural gas revenue	**2,079**	1,645
Other contract revenue [1]	**2**	3
Total revenue from contracts with customers	**2,081**	1,648
Alternative revenue [2]	**(34)**	(6)
Other revenue [3]	**36**	72
Total revenue	**2,083**	1,714

[1] Other contract revenue includes utility customer connection fees and agreements with certain customers to provide transportation of natural gas over utility owned infrastructure.

[2] Alternative revenue includes the Earnings Sharing Mechanism, which recognizes the 50/50 sharing of variances from the allowed ROE, the RSAM, and flow-through variances related to industrial and other customer revenue.

[3] Other revenue is primarily comprised of other flow-through and regulatory deferral adjustments resulting from cost recovery variances in regulated forecasts used to set gas delivery rates.

18. OTHER INCOME

($ millions)	**2022**	2021
Dividend income from FHI (note 24)	**100**	-
Equity component of AFUDC (note 6)	**13**	7
Net periodic pension and post-employment benefit cost	**9**	4
Interest income	**1**	1
Total other income	**123**	12

19. FINANCE CHARGES

($ millions)	**2022**	2021
Interest on long-term debt	**147**	147
Interest on short-term debt	**7**	1
Debt component of AFUDC (note 6)	**(8)**	(4)
Net interest on debt	**146**	144
Finance charges paid to FHI (note 24)	**100**	-
Total finance charges	**246**	144

20. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

The supplementary information to the Consolidated Statements of Cash Flows for the years ended December 31 are as follows:

($millions)	**2022**	2021
Interest paid	**152**	146
Interest paid to FHI (note 24)	**100**	-
Net income tax paid (refunded)	**16**	(16)

Change in working capital		
Accounts receivable and other current assets	**(201)**	(20)
Inventories	**(47)**	(16)
Prepaid expenses	**-**	(1)
Accounts payable and other current liabilities	**193**	131
Total change in working capital	**(55)**	94

Non-Cash Investing Activities

($ millions)	**2022**	2021
As at December 31		
Accrued capital expenditures	**54**	59

21. INCOME TAXES

Deferred Income Tax

The significant components of deferred income tax assets and liabilities consisted of the following as at December 31:

($ millions)	**2022**	2021
Deferred income tax liability (asset)		
Property, plant and equipment	**696**	641
Intangible assets	**33**	27
Regulatory assets	**195**	156
Regulatory liabilities	**(172)**	(88)
Employee future benefits	**(36)**	(32)
Other	**(48)**	(30)
Net deferred income tax liability	**668**	674

As at December 31, 2022 and 2021, the Corporation has no non-capital losses carried forward.

Provision for Income Taxes

($ millions)	**2022**	2021
Current income tax expense	**15**	30
Deferred income tax expense	**(6)**	57
Regulatory adjustment (note 8)	**2**	(41)
Deferred income tax expense, net of regulatory adjustment	**(4)**	16
Income tax expense	**11**	46

21. INCOME TAXES (continued)

Variation in Effective Income Tax Rate

Income taxes vary from the amount that would be computed by applying the Canadian federal and BC combined statutory income tax rate of 27.0 per cent (2021 – 27.0 per cent) to earnings before income taxes as shown in the following table for the years ended December 31:

	2022	2021
Combined statutory income tax rate	**27.0%**	27.0%
($ millions)		
Statutory income tax rate applied to earnings before income taxes	**65**	62
Preference share dividends	**(27)**	-
Items capitalized for accounting but expensed for income tax purposes	**(5)**	(1)
Difference between capital cost allowance and amounts expensed for accounting purposes	**(29)**	(21)
Difference between employee future benefits paid and amounts expensed for accounting purposes	**-**	3
Difference between regulatory accounting items and amounts claimed for tax purposes	**10**	6
Other	**(3)**	(3)
Actual income tax expense	**11**	46
Effective income tax rate	**4.6%**	20.2%

Taxation years 2017 and prior are no longer subject to examination in Canada. An examination of the open tax years subsequent to 2017 by the Canada Revenue Agency could result in a change in the liability for unrecognized tax benefits.

22. FINANCIAL INSTRUMENTS

The Corporation categorizes financial instruments into the three-level hierarchy based on inputs used to determine the fair value:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

Recurring Fair Value Measures

The following table presents the fair value of assets and liabilities that are accounted for at fair value on a recurring basis as at December 31, all of which are Level 2 of the fair value hierarchy. Contracts that are "in the money" are included in accounts receivable and other current assets or in long-term other assets, and "out of the money" are included in accounts payable and other current liabilities or in long-term other liabilities.

($ millions)	**2022**	2021
Assets		
Current	**47**	4
Total assets	**47**	4
Liabilities		
Current	**(70)**	(4)
Long-term	**(37)**	-
Total liabilities	**(107)**	(4)
Total liabilities, net	**(60)**	-

22. FINANCIAL INSTRUMENTS (continued)

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions which are netted where the intent and legal right to offset exists. The following table presents the potential offset of counterparty netting.

($ millions)	**Gross Amount Recognized on Balance Sheet**	**Counterparty Netting of Natural Gas Contracts**	**Cash Collateral Posted**	**Net Amount**
As at December 31, 2022				
Accounts receivable and other current assets	**47**	**(15)**	**28**	**60**
Accounts payable and other current liabilities	**(70)**	**15**	**-**	**(55)**
Other liabilities	**(37)**	**-**	**-**	**(37)**
As at December 31, 2021				
Accounts receivable and other current assets	4	-	7	11
Accounts payable and other current liabilities	(4)	-	-	(4)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception.

FEI enters into physical natural gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. Swap contracts are agreements between two parties to exchange streams of payments over time according to specified terms. Swap contracts require receipt of payment for the notional quantity of the commodity based on the difference between a fixed price and the market price on the settlement date. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

Natural gas contracts held by FEI are subject to regulatory recovery through rates. As at December 31, 2022, natural gas contract derivatives are not designated as hedges and any unrealized losses and gains arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

($ millions)	**2022**	2021
Unrealized net loss recorded to current regulatory assets	**60**	-

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's Consolidated Statements of Cash Flows.

Volume of Derivative Activity

As at December 31, 2022, the Corporation had various natural gas derivative contracts subject to regulatory deferral that will settle on various expiration dates through 2025. The volumes related to these natural gas derivatives are outlined below:

(petajoules)	**2022**	2021
Natural gas physically-settled supply contracts	**148**	144
Natural gas financially-settled commodity swaps	**51**	2

22. FINANCIAL INSTRUMENTS (continued)

Financial Instruments Not Carried At Fair Value

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. The Corporation uses the following methods and assumptions for estimating the fair value of financial instruments:

- The carrying values of cash, accounts receivable, accounts payable, other current assets and liabilities and borrowings under credit facilities on the Consolidated Balance Sheets of the Corporation approximate their fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, the Corporation uses quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The use of different estimation methods and market assumptions may yield different estimated fair value amounts. The following table includes the carrying value, excluding unamortized debt issuance costs, and estimated fair value of the Corporation's long-term debt as at December 31.

		2022		2021	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,295**	**3,101**	3,145	3,817

23. CREDIT FACILITIES

As at December 31, 2022, the Corporation had a $700 million syndicated operating credit facility in place, which matures in July 2027, and a $55 million uncommitted letter of credit facility in place which matures in March 2024.

The weighted average interest rate on borrowings under the Corporation's operating credit facility at December 31, 2022, was approximately 4.31 per cent (December 31, 2021 – 0.14 per cent).

The following summary outlines the Corporation's credit facilities as at December 31:

($ millions)	**2022**	2021
Operating credit facility	**700**	700
Letter of credit facility	**55**	55
Draws on operating credit facility	**(203)**	(242)
Letters of credit outstanding	**(54)**	(42)
Credit facilities available	**498**	471

In December 2022, FEI executed an amendment to its operating credit facility to incorporate a Sustainability Linked Loan ("SLL") component. The SLL will incorporate sustainability performance targets considering avoided emissions from renewable gas and capital project opportunities with Indigenous participation. The amendment to the credit facility has been approved by the BCUC.

24. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FortisBC Inc. ("FBC") and Aitken Creek Gas Storage ULC ("ACGS"), in financing transactions and to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2022**	2021
Other income received from FHI (a)	**100**	-
Operation and maintenance expense charged to FBC (b)	**8**	7
Operation and maintenance expense charged to FHI (c)	**1**	1
Operation and maintenance expense charged to ACGS (d)	**1**	1
Total related party recoveries	**110**	9

(a) The Corporation received dividend income from FHI relating to a $3,000 million (2021 - $nil) investment in preferred shares, as part of a tax loss utilization plan ("TLUP") implemented in the second quarter of 2022.

(b) The Corporation charged FBC for natural gas sales, office rent, management services and other labour.

(c) The Corporation charged FHI for office rent, management services and other labour.

(d) The Corporation charged ACGS for management services and other labour.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2022**	2021
Finance charges paid to FHI (a)	**100**	-
Gas storage and purchases charged by ACGS (b)	**37**	38
Operation and maintenance expense charged by FHI (c)	**13**	12
Operation and maintenance expense charged by FBC (d)	**7**	6
Total related party costs	**157**	56

(a) FHI charged the Corporation interest on $3,000 million (2021 - $nil) of intercompany subordinated debt, as part of a TLUP implemented in the second quarter of 2022.

(b) ACGS charged the Corporation for the lease of natural gas storage capacity and natural gas purchases.

(c) FHI charged the Corporation for corporate management services and governance costs.

(d) FBC charged the Corporation for electricity purchases, management services, and other labour.

24. RELATED PARTY TRANSACTIONS (continued)

Balance Sheet Amounts

The amounts due from related parties, included in accounts receivable and other current assets on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, were as follows as at December 31:

	2022		2021	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
ACGS	**-**	**(4)**	-	(5)
FHI	**-**	**(2)**	-	(2)
FBC	**-**	**-**	1	-
Total (due to) due from related parties	**-**	**(6)**	1	(7)

25. COMMITMENTS

The following table sets forth the Corporation's estimated commitments due in the years indicated:

As at December 31, 2022	**Total**	**Due within 1 Year**	**Due in Year 2**	**Due in Year 3**	**Due in Year 4**	**Due in Year 5**	**Due after 5 Years**
($ millions)							
Long-term debt[1] (note 12)	**3,295**	**-**	**-**	**-**	**150**	**-**	**3,145**
Interest obligations on long-term debt (note 12)	**2,647**	**152**	**152**	**152**	**150**	**148**	**1,893**
Gas purchase obligations (a)	**4,791**	**757**	**368**	**346**	**296**	**260**	**2,764**
Other (b)	**25**	**18**	**4**	**2**	**1**	**-**	**-**
Total	**10,758**	**927**	**524**	**500**	**597**	**408**	**7,802**

[1] Excludes unamortized debt issuance costs.

(a) The Corporation enters into contracts to purchase natural gas, renewable gas, and natural gas transportation and storage services from various suppliers. These contracts are used to ensure that there is an adequate supply of natural gas and renewable gas to meet the needs of customers and to minimize exposure to market price fluctuations. The natural gas purchase obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2022.

The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers. During 2022, FEI entered into certain long-term supply agreements to acquire renewable gas over a 20-year period from a portfolio of landfill sites and from an anaerobic digester facility, up to a combined maximum annual volume of 9.3 petajoules. Both agreements were approved by the BCUC.

(b) Included in other commitments are building and vehicle leases, and defined benefit pension plan funding obligations.

In addition to the items in the table above, the Corporation has issued commitment letters to customers who may meet the criteria to obtain Demand Side Management ("DSM") funding under the DSM Expenditures Plan approved by the BCUC. As at December 31, 2022, the Corporation had issued $14 million (December 31, 2021 - $16 million) of commitment letters to these customers.

25. COMMITMENTS (continued)

In January 2012, two unrelated parties collectively purchased a 15 per cent equity interest in the MHLP, which at the time was a wholly owned limited partnership of the Corporation. These non-controlling interest owners hold a put option which, if exercised, would oblige the Corporation to purchase the non-controlling interest owners' 15 per cent voting share in MHLP for cash. For rate-making purposes, these non-controlling interests are considered equity and if FEI was required to purchase these non-controlling interests, FEI would fund the transaction with an equity issuance. Accordingly, the Corporation has presented these redeemable non-controlling interests as equity.

26. GUARANTEES

The Corporation had letters of credit outstanding at December 31, 2022 totaling $54 million (December 31, 2021 - $42 million) primarily to support the funding of one of the Corporation's pension plans and have been applied against FEI's $55 million uncommitted letter of credit facility.

Attachment 2: Alberta Generic Cost of Capital (GCOC) proceedings in 2015-2016 (AUC Proceeding ID 20622)

ALBERTA UTILITIES COMMISSION

2016-2017 GENERIC COST OF CAPITAL

APPLICATION NO. #20622-A001;

PROCEEDING ID #20622

EVIDENCE OF DR. SEAN CLEARY, CFA, BMO PROFESSOR OF FINANCE

SUBMITTED ON BEHALF OF:

THE UTILITIES CONSUMER ADVOCATE (UCA) ON ALLOWED ROE, CAPITAL STRUCTURE & RELATED ISSUES

March 23, 2016

2016-2017 GENERIC COST OF CAPITAL
APPLICATION NO. #20622-A001; PROCEEDING ID #20622
EVIDENCE OF DR. SEAN CLEARY, CFA, BMO PROFESSOR OF FINANCE

TABLE OF CONTENTS

1. INTRODUCTION

1.1 Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am currently the BMO Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

Most recently, I served as an expert witness on behalf of the Utilities Consumer Advocate (UCA) of Alberta in 2014, where I prepared evidence and testified regarding appropriate risk margins for commodity risk for regulated Alberta utilities. I also served as an expert witness for the UCA of Alberta in the generic cost of capital proceedings in 2013-14, preparing evidence and testifying regarding an appropriate ROE and capital structure for regulated Alberta utilities. Prior to that, I provided a report for the Chicken Farmers of Ontario (CFO) recommending an appropriate ROE, capital structure, and cost of capital for the average chicken farmer in Ontario. This information was used in determining a new pricing formula for Ontario chickens.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, since most of my research has dealt with empirical corporate finance and capital market issues, consisting of 28 publications. My work has been cited over 2,000 times. Most of this work has dealt directly or indirectly with capital structure and cost of equity issues. I have authored or co-authored 13 finance text books, all of which deal with capital structure, cost of equity, and cost of capital analysis. The four editions of "Introduction to Corporate Finance" (co-authored with Laurence Booth, University of Toronto) include estimates of the cost of equity and cost of capital for actual companies. I estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is included in Appendix A to my evidence.

1.2 Purpose of Testimony

With respect to the 2016 Generic Cost of Capital Proceedings in Alberta, the Utilities Consumer Advocate (UCA) of Alberta has requested that I provide recommendations regarding allowable ROEs and equity ratios for Alberta utilities.

1.3 Summary of ROE Estimates

Section 2 shows that global economic conditions have stabilized, as have Canadian capital market conditions. While real GDP growth for Alberta is predicted to be below average in 2016, it is expected to experience positive growth (1.6%), before growth increase above 2% in subsequent years. Relatedly, oil prices are expected to continue their rise which has begun over the last few weeks. So overall, we can say that the Canadian and Alberta economies are entering a recovery period that will be followed by more normal growth in the intermediate term. In any event, economic and capital market conditions are far from those existing at the peak of the 2008-2009 financial crisis. Regardless, regulated utilities with established territories are not as influenced by economic cyclicality to the extent of traditional businesses. My evidence confirms this is true for Alberta utilities.

Several approaches were used to estimate the appropriate generic ROE for Alberta utilities including the CAPM, DCF and Bond Yield Plus Risk Premium (BYPRP) models. Based on an equal weighting of these three approaches, I estimate the following best estimate and ranges for an appropriate ROE:

Year	**CAPM (1/3rd)**	**DCF (1/3rd)**	**BYPRP (1/3rd)**	**Overall Range**	**Best Estimate**
2016-2017	6.0	8.0	7.0	4.2-8.9	**7.0**

The details of all estimates are provided herein, as is the reason for choosing an equal weighting scheme.

This estimate is very reasonable when compared to expected long-term overall stock market returns in the 7-9%, when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 7-9% range are consistent with experienced long-term real stock returns of 6-7%. The ROE estimate is also consistent with our current low interest rate environment, which can be expected to change only gradually over the next few years.

1.4 Summary of Comments on Capital Structure

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk, it is not surprising that they have been able to generate ROEs at or above the allowed ROEs for 9 of the last 10 years, and with these ROEs also displaying low volatility.

My analysis of the global, Canadian and Alberta economies suggests that economic and capital market conditions are normalizing and are far removed from the conditions existing in 2009 when the Board provided a 2% across the board increase in equity ratios. Utilities currently benefit from very low base interest rates, which has provided them with even lower costs of long-term borrowing than during the 2013 hearings, despite an increase in yield spreads. The Board removed 1% of this buffer in its 2013 Decision, and I recommend that they remove the other 1% in this Decision. In other words, I am recommending a reduction in the equity ratio of 1% across the board. My risk analysis suggests this is reasonable, and the credit metric analysis provided by Mr. Stauft shows that such a reduction would leave credit metrics well within the desired metric ranges according to criteria used by the Board, and by debt rating agencies.

2. THE ECONOMY AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE

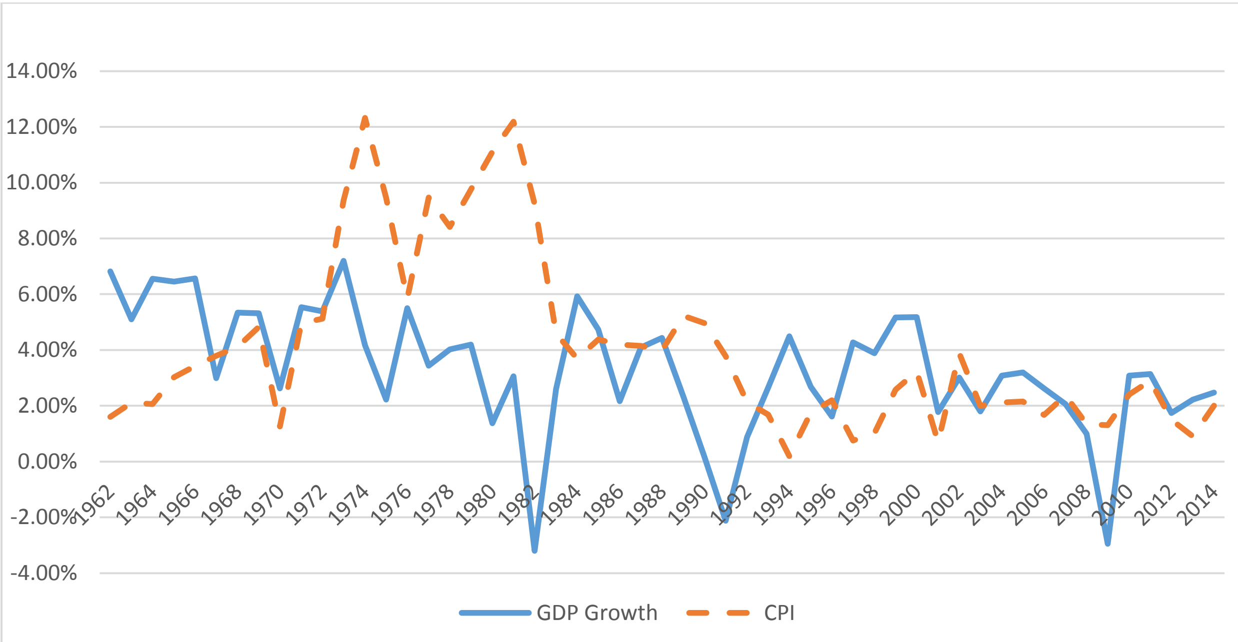
2.1 The Past and Present

2.1.1 Historical Evidence

The figure below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index (CPI) over the 1962 to 2014 period. The graph shows that real GDP growth has generally been in the 2 to 6 percent range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average for GDP growth over the entire period was 3.3% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.6% (median 2.7%) over the 1992 to 2014 period. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from the figure, and also as measured by the standard deviation reported in Table 1.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2014)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2014)

	1962-2014 (%)		1992-2014 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.28	4.06	2.57	1.86
Median	3.09	3.23	2.66	1.99
Max	7.20	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.24	3.13	1.68	0.86

Data Source: Statistics Canada.

The 1962-2014 stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average of 1.86% (median 1.99%). CPI growth has also been very stable during this latter period, which is obvious from the graph, and also by the huge decline in standard deviation from 3.1% to 0.9%. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2 Changes since the 2013 Decisions

The Commission noted in its 2013 Decision (page 6, paragraph 37) that:

> "All parties agreed that current global economic and Canadian capital market conditions have improved since the time of the 2011 GCOC proceeding resulting in Decision 2011-474. The parties, however, disagreed on the amount of risk remaining in capital markets."

At that time, the Consensus Economics (December 2013) forecasts of Canadian GDP growth for 2014 and 2015 were 2.3% and 2.5%, while the Bank of Canada's October 2013 *Monetary Policy Report (MPR)* anticipated similar growth rates at 2.3% and 2.6% for 2014 and 2015 respectively. In fact, real GDP growth turned out to be in line with these forecasts – slightly above in 2014 at 2.5%, and slightly below in 2015 at 2.4% (as estimated in the Bank's January 2016 MPR).

Of course, several stories have unfolded since 2014 including, but not limited to: strong growth in the U.S. economy, and the implementation of the gradual withdrawal of monetary stimulus by the U.S. monetary authorities; the decline of oil prices into the $30 U.S. range; a decline in non-oil commodity prices; and, the decline in the value of the Canadian dollar relative to the U.S. greenback. Each of these issues will be discussed in greater detail in Section 2.2, but I will note now that this has contributed to lower than expected interest rates in Canada over 2014 and 2015, and at the start of 2016.

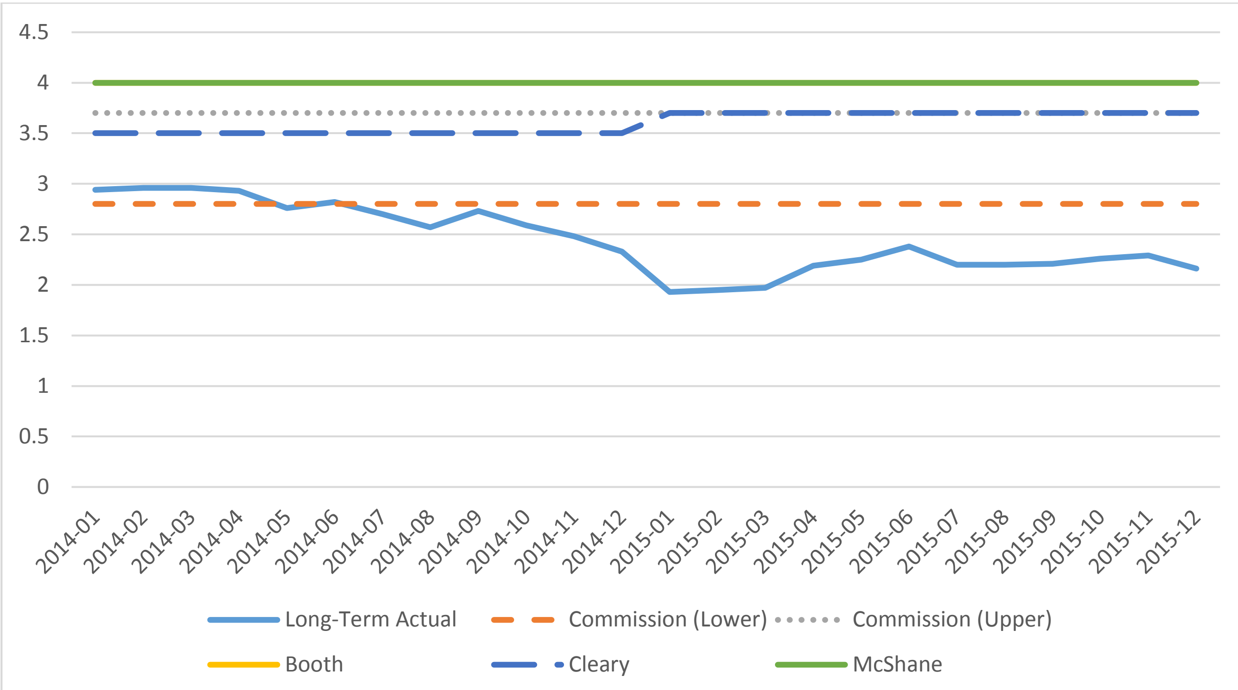
The Bank lowered its overnight lending rate twice during the first half of 2015, and it currently sits at 0.5%, which has contributed to lower than expected short-term rates. At the other end of the yield curve, Canadian long-term government bond yields did not increase during 2014 and 2015 as had been predicted. In fact, they declined by about 10 basis points during 2014 (averaging 2.7%), before declining significantly in 2015, averaging 2.2%, which is the level at which they ended the year.

At the time of the last decision, the Commission referred to the April 2014 Consensus Economics forecasts for government 10-year yields, which were 2.7% for 2014 and 3.2% for 2015. They then added the long-term average spread between 10-year and 30-year government yields of 50 basis points, to arrive at estimates for 30-year government bond yields of 3.2% and 3.7% for 2014 and 2015 respectively. Noting that forecasts had been too high in 2011, the Commission used the actual prevailing long-term yield at the time of 2.8% as a lower bound, and used the 3.7% Consensus estimate for 2015 as its upper bound. Figure 2 shows that the estimates provided by all experts and the Commission were above the 2014 actual rate of 2.7% (although very close to the Commission's lower bound using the prevailing 2014 rate). The 2015 long-term yields of 2.2% were well below all estimates, even the Commission's lower bound.[1]

[1] Note that the spread between 10-year and 30-year bond yields remained stable during 2014, hovering close the long-term average 50 basis point spread that was added to the 10-year yield forecasts. During 2015, this spread increased, averaging 0.68%, and ending the year at 0.76%.

FIGURE 2

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2014-2015)



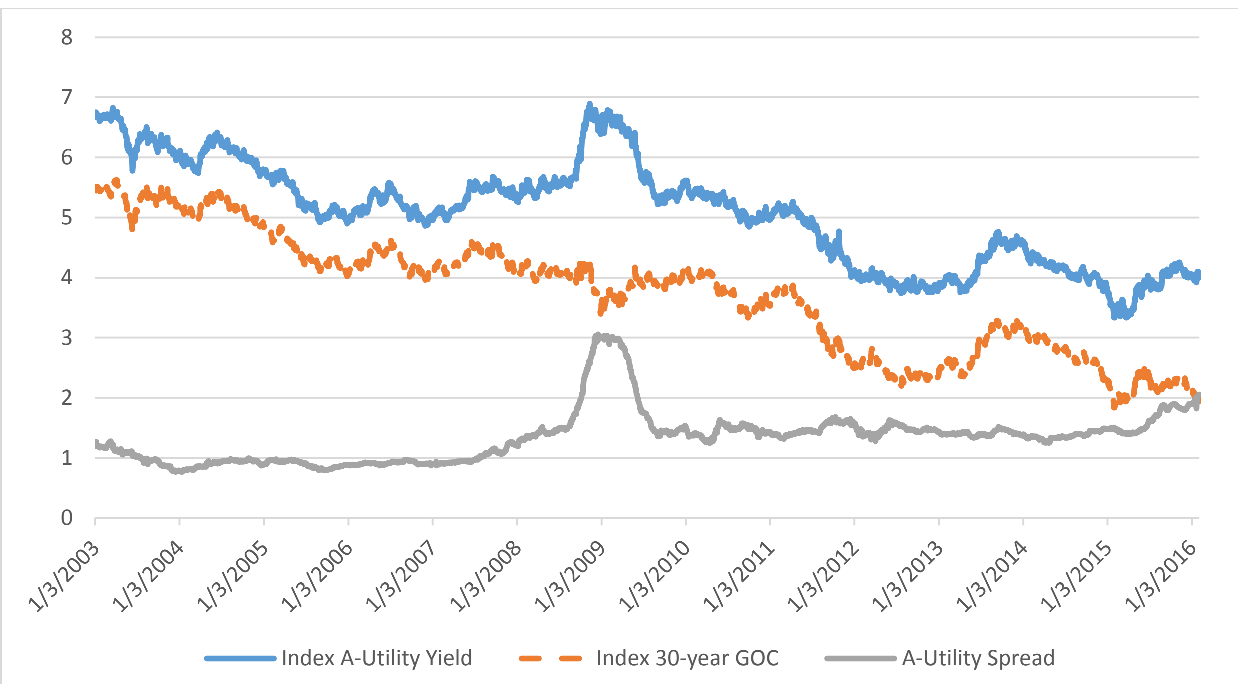
Data Source: Bank of Canada website at http://www.bankofcanada.ca.

During the 2013 proceedings, it was noted that yield spreads had declined significantly from their previous abnormal high levels during the 2009 proceedings, but remained somewhat elevated. For example, the A-rated Canadian Utility spread was noted to be 141 basis points in December 2013, (just as it was in July 2011), above the 2003-07 average spread of 95 basis points, but well below the peak levels of around 300 basis points during the December 2008-March 2009 period. This observation was consistent with the views mentioned previously that the economy had stabilized, but that some risks remained.

Figure 3 reports the yields for long-term Canada government bonds and A-rated Canadian utilities over the 2003 to February 3, 2016 period. As it turns out, the spreads remained quite stable in the 1.3 to 1.5 percent range throughout 2014 and through the first half of June 2015. Combining this observation with low and declining long-term government yields, we can see that the cost of issuing long-term bonds declined throughout the period for A-rated Canadian utilities, hitting a minimum of 3.33% in February 2015, at a time when long-term government yields were 1.83% and the yield spread was 1.50%. In late June 2015, spreads began to widen above 1.5% and they hit 1.9% by the end of 2015, before increasing further to 2.06% by February 3, 2016. Despite this increase in yield spreads, the cost of long-term borrowing to A-rated utilities has actually declined since 2013. For example, the average yields were 4.24% and 4.14% during 2013 and 2014, years during which the corresponding yield spreads averaged 1.41% and 1.37% respectively. During 2015, the average yield for A-rated utility bonds was lower at 3.82%, despite a higher average yield spread of 1.63%. While the yield spread had increased to 1.90% by the end of 2015 and to 2.06% by February 3, 2016, the yields on A-rated utility bonds were actually lower than in 2013 and 2014 at 4.05% in December 2015 and 4.03% on February 3, 2016 – of course this is due to the decline in risk-free government bond yields, which form the base rate for utility borrowing.

FIGURE 3

A-UTILITY YIELDS (2003-February 3, 2016)

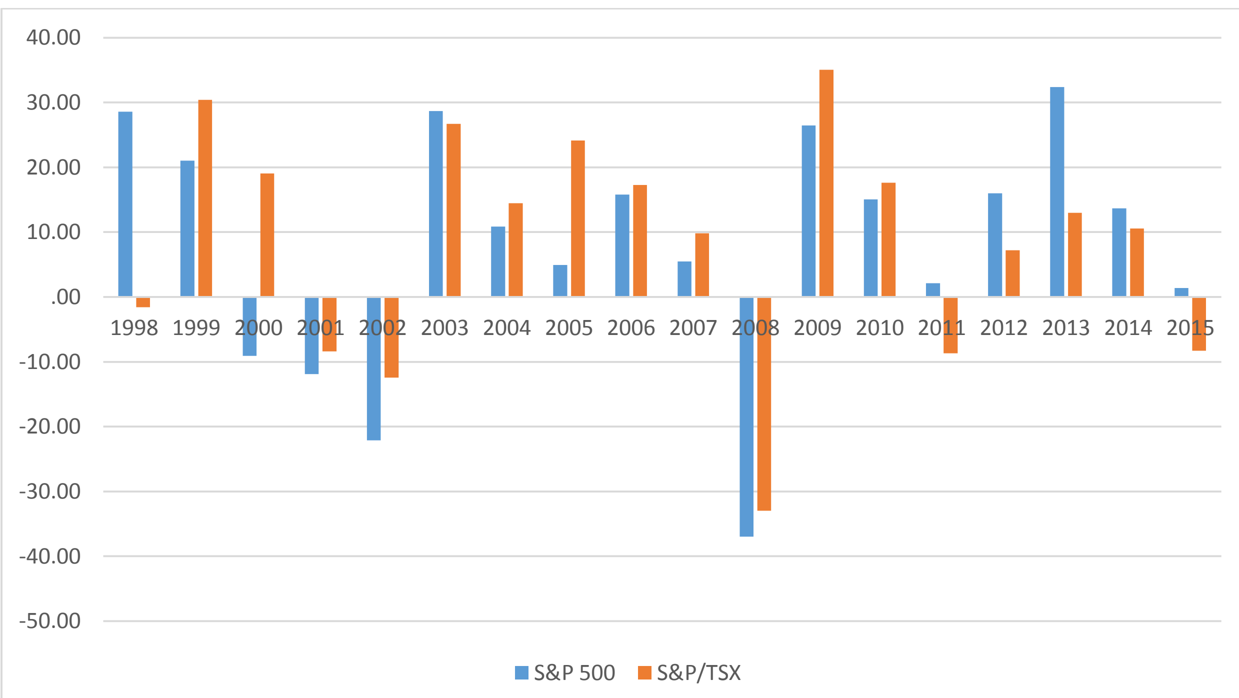


Source: Bloomberg.

Canadian stock markets provided an average return of 10.6% in 2014, before providing for a loss of 8.3% in 2015 as declining commodity prices took their toll on the Canadian stock market. U.S. markets fared better, providing an average return of 13.7% in 2014 and +1.4% in 2015. Over the entire 1998-2015 period stocks in Canada provided an average return of 8.5%, while U.S. stocks provided an average return of 7.9%. These figures are low relative to longer term historical averages due to several factors affecting stock returns over this period including the high tech crash of 2001-02, the financial crisis of 2008-09, the Euro crisis, and more recent declines in commodity prices. However, the lower experienced returns are consistent with current market expectations (discussed in Section 2.3.3) that are based on lower inflation expectations over more recent periods, as monetary authorities around the globe have strived to maintain inflation levels in the area of 2%.

FIGURE 4

STOCK MARKET RETURNS - (1998-2015)



Source: Bloomberg

The trailing price-earnings (P/E) ratio for the S&P/TSX Composite Index stood at 19.8 on February 5, 2016, while the P/E ratio for the U.S. S&P 500 Index was 16.9 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below 15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 17 to 20 range in Canada and the U.S. are in familiar territory. This is also true of dividend yields which were 2.4% in the U.S. and 3.4% in Canada on February 5, 2016. Thus, despite all the volatility in global, U.S. and Canadian stock markets during January of 2016, these stock market indicators were close to long-term averages. In fact, by February 17, 2016, the S&P/TSX Composite Index had recovered most of its January 2016 losses and was down only 1.1%, giving it the best year-to-date performance of the top 24 major stock markets in the world at that time,[2] and by March 11th the TSX was actually up 3.9% on the year-to-date. The implied volatility indexes in Canada and the U.S. have averaged about 20 through time. The Canadian and U.S. VIX indices stood at 21.6 and 17.3 respectively as of March 14, 2016, indicating normal volatility in both Canada and the U.S., and nowhere near the levels of 70 experienced in 2008-09. Thus, while it has been a volatile period for stock markets, we are hardly in a period of financial crisis.

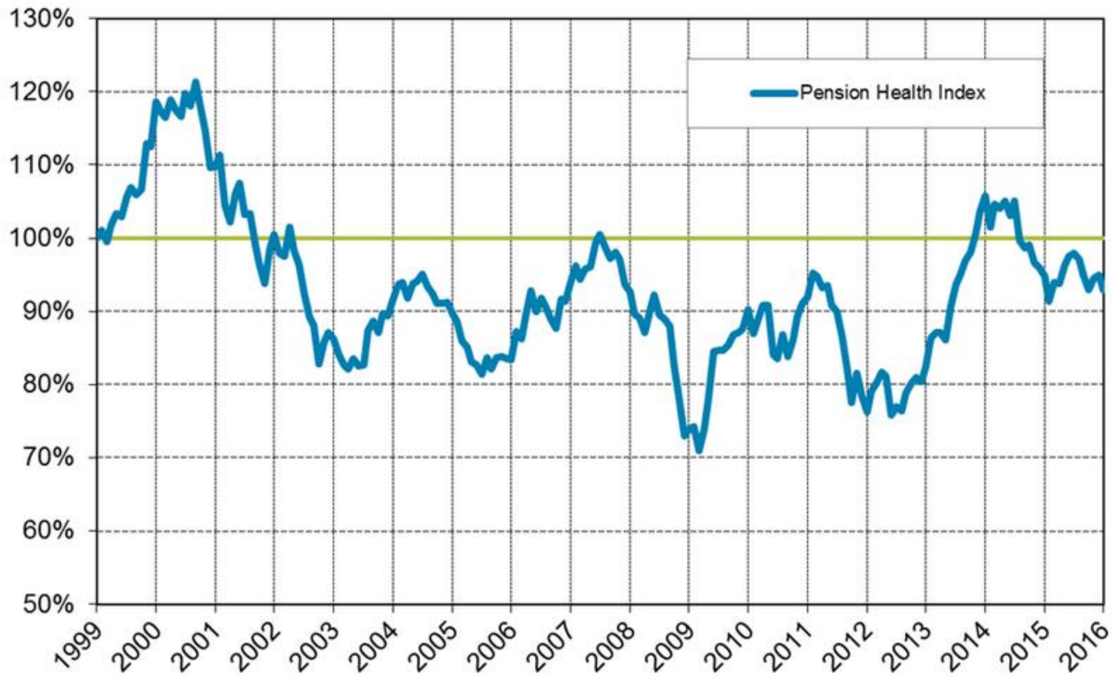
Pension fund health has been a closely watched and important concern in recent years. Poor stock returns during the crisis, combined with extremely low levels of interest rates hit the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 5 depicts the value of this index over the 1999 to 2015 period. The index ended 2015 down to 93% from 95% at the start of the year. Mercer noted that the 2015 decline in funded status was due to poor Canadian equity market performance and declining long-term bond yields. The poor Canadian stock performance was offset to a large degree by the returns on U.S. stock investments, especially to Canadian-based investors that did not currency hedge their

[2] Source: "TSX hits six-week high," Globe and Mail, Report on Business, February 18, 2016, page B1.

U.S. investments as the S&P 500 provided unhedged returns in CAD of over 21%.[3] While 93% is down slightly from the start of the year, and is lower than the level of 106% at the start of 2014 (which was its highest level since 2001), it is near 100% and well above the all-time low of around 70% in early 2009. So again, this measure does not indicate market conditions are anywhere near crisis levels.

FIGURE 5

MERCER PENSION HEALTH INDEX - (1999-2015)



Source: http://www.mercer.ca/en/newsroom/2015-ends-on-a-down-note-for-pension-plans.html, January 5, 2016

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3 Source: "2015 ends on a down note for pension plans," http://www.mercer.ca/en/newsroom/2015-ends-on-a-down-note-for-pension-plans.html, January 5, 2016.

2.2 The Future

2.2.1 Global Economic Activity

The global economy has faced several challenges since 2008, but is expected to grow at a moderate pace in 2016 and 2017. For example, Table 2 shows the January 2016 Consensus Economics Inc. Forecasts for average global real GDP growth figures of 2.7% and 3.0%, while the Bank of Canada's January 2016 Monetary Policy Report (MPR) estimates were slightly higher at 3.3% and 3.6%. Table 2 shows that the expected global improvements are based in large part on expectations that the U.S. economy will continue to grow steadily over 2016 and 2017 in the 2.4-2.5% range, while the Euro zone will continue to rebound back closer to normal growth levels with expected growth rates of 1.6-1.7% for 2016-17.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2016-2017)

Real GDP Growth (%)	**2016**		**2017**	
	Consensus	**Bank of Canada**	**Consensus**	**Bank of Canada**
World	2.7	3.3	3.0	3.6
U.S.	2.4	2.4	2.5	2.5
Euro Zone	1.7	1.6	1.7	1.6

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

The Bank of Canada notes in its January 2016 MPR that global growth will be the result of diverging prospects at the individual country level. They note that U.S. economic growth has been healthy, with consumer confidence improving, wage growth showing signs of increasing, and increases in the levels of business investment outside of commodity-related sectors. They also note that the U.S. Federal Reserve's implementation of gradual withdrawal of monetary stimulus had only a minor impact on market prices, since it was widely anticipated. The Bank suggests that, in contrast to the U.S., expected areas of economic growth in Japan and the Euro area will be driven by "accommodative monetary policy, low oil prices and past exchange rates."

At the same time, as a result of a rebalancing from manufacturing to service industries, the Bank forecasts that China's growth will stabilize at just over 6% by the end of 2017, down from just over 7% in 2014. While the Bank expects infrastructure investment to slow, it will "remain robust through 2017, in line with the Chinese government's stated priority to address ongoing infrastructure needs." They also note mixed economic growth messages in other emerging economies. While the recession in Brazil is now expected to last longer than previously expected, they forecast improvements in growth in oil-importing emerging markets such as emerging Asian countries. Finally, they expect continued solid growth in India of 7-8%.

2.2.2 Canada's Outlook

Of course, three of the main stories contributing to this divergence of global fortunes have been the falling price of oil, the decline in other commodity prices, and the continued strengthening of the U.S. dollar. These stories have had a similarly diverse impact on the Canadian economy. For example, the Bank shows in Chart 13 (page 17) of the January MPR that over the January 2013-October 2015 period, output growth followed very different patterns for: (1) oil and gas related industries (9 percent of GDP); (2) non-energy commodity related industries (7 percent of GDP); and, (3) non-resource sector industries (84 percent of GDP). In particular, the graph shows that output grew faster in sectors (1) and (2) during 2013, but since mid-2014 the decline in oil and gas related industries has been significant, while there has been a slight decline in output for non-energy commodities. In contrast, output from other sectors of the economy have continued to grow at a steady rate.

Oil prices had declined by over 70 percent of their June 2014 peak as of January 2016. While the Bank does not make forecasts for oil prices, they felt that risks were tilted to the downside in the near term based on existing inventories, climate forecasts, and geopolitical risks (which could impact prices in either direction, depending on the scenario). In contrast, the Bank feels the risks of oil price changes are tilted to the upside in the medium term, as reductions in investment in the oil industry impact supply. Interviews with energy firms in the fall of 2015 suggested that US$45 per barrel of WTI was a break-even price. Not surprisingly, oil firms cut capital spending by about 40 percent in 2015, and estimated they would reduce 2016 spending by 25 percent, if prices remained in the low US$30s. Firms have also worked at improving productivity and have reduced labour costs through layoffs and by cutting salaries and bonuses.

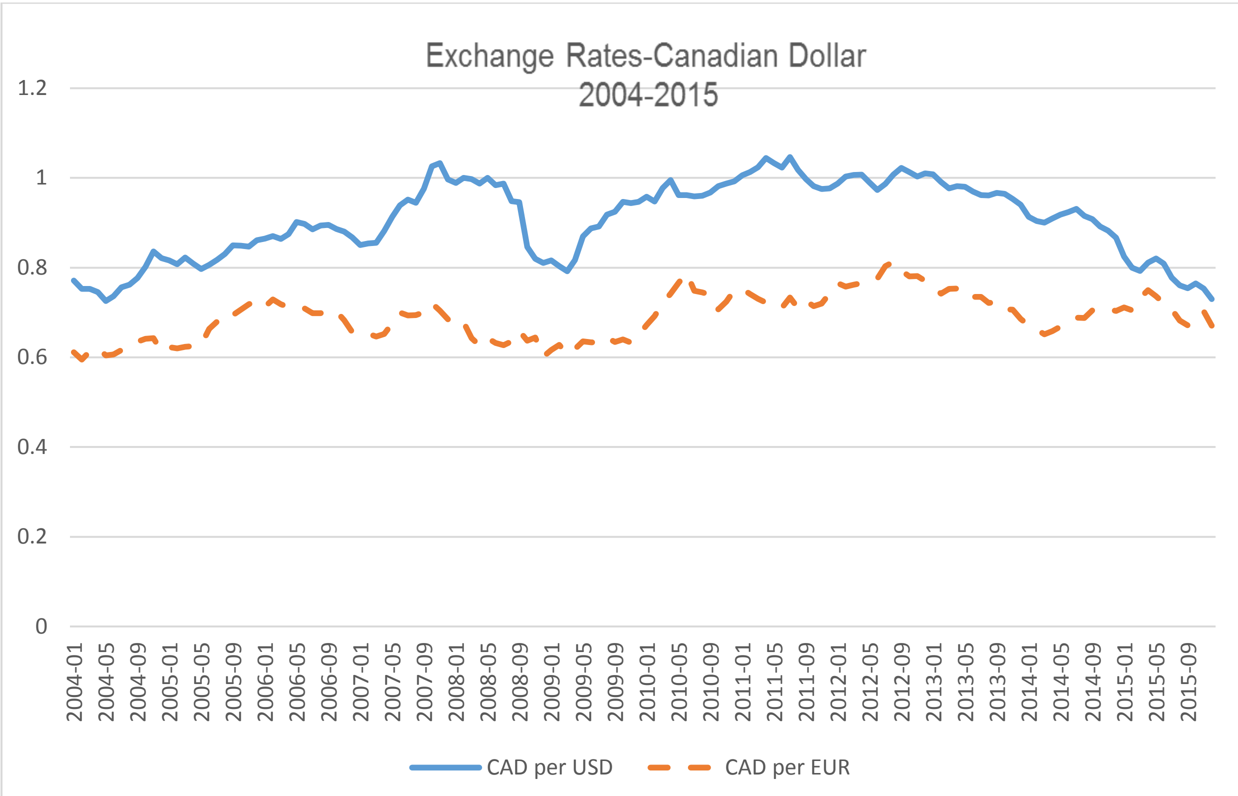
Reduced commodity prices have led to an appreciation in the currencies of commodity importers, and a depreciation in the currencies of commodity exporters. Figure 2 depicts the significant decline in the Canadian dollar relative to the U.S. dollar (USD) since 2013. The graph shows that the CAD traded around par during at the start of 2013, but has trended downward, sitting at around $0.73 at the end of 2015. Obviously, such a rapid and severe decline in the value of the loonie has impacted our economy, as discussed below. The expected improvement in exports due to the decline in the dollar have been slow to materialize, but are now doing so, and are expected to improve in 2016 and 2017. Finally, the Bank of Canada's easy monetary policy and the resulting accommodative financial conditions[4] have provided ongoing support to the economy.

It is always difficult to forecast exchange rates (which is why the Bank does not make such forecasts). However, the general consensus is that the CAD will appreciate slightly going forward. For example, Mr. Buttke's evidence (Table 7, page 14) provides Bloomberg forecasts for the CAD of $.7297 U.S. by Q2 2016, $.7692 in 2017, $.8065 in 2018, $.8264 in 2019, and $.8547 in 2020. Consensus Economics forecasts also indicate expectations that the CAD will appreciate – to $.7283 by April 2016, $.7474 by January 2017, and to $.7680 by January 2018. In fact, by March 11, 2016 the CAD had appreciated to $.7558 per USD.

[4] For example, in the Bank of Canada's winter 2016 Business Outlook Survey, most firms surveyed characterized credit as "easy or relatively easy to obtain."

FIGURE 6

EXCHANGE RATES – CANADIAN DOLLAR (2004-2015)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

As a result of the factors discussed above Canada's economy has experienced slower than expected GDP growth during 2015, resulting in a slight increase in the overall unemployment rate to 7.1%. Lower oil and commodity prices have depressed activity and investment in those sectors and the provinces that are most heavily reliant upon those sectors (i.e., Alberta, Newfoundland and Saskatchewan). In contrast, the Bank predicts that non-commodity export industries that are sensitive to the exchange rate will outperform, which will lead to an increase in non-resource based business investment.

Combining all of these varied effects is never easy, but the Bank predicts that the Canadian economy will continue its adjustment to lower oil and commodity prices, with the worst of these adjustments being behind us. The Bank predicts, at the aggregate level, that household expenditures will expand moderately, and that real GDP growth will improve from 0.3% during

2015 to 1.4% in 2016 and 2.4% in 2017. Table 3 shows that the 2016 and 2017 forecasts are in line with, but slightly higher than the Consensus forecasts (1.7% and 2.2%), and with those of the IMF (1.7% and 2.4%) and the OECD (2.0% and 2.3%).

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2016-2017)

	2016	2017
Conf. Board of Canada	1.8	2.3
CIBC World Markets	1.7	2.3
IHS Economics	1.6	2
Citigroup	1.7	2.1
BMO Capital Markets	1.6	2.2
Desjardins	1.7	2.2
Econ Intell Unit	1.8	2.1
EconoMap	1.6	2.3
Oxford Economics	1.7	2.2
JP Morgan	1.5	2.2
National Bank	1.6	1.7
RBC	1.8	2.6
TD Bank	1.6	1.8
University of Toronto	1.8	3
Scotia Econ	1.6	2.3
Informetrica	2.2	2.1
Average	**1.7**	**2.2**
Median	**1.7**	**2.2**
Max	**2.2**	**3**
Min	**1.5**	**1.7**
IMF (Oct 15)	**1.7**	**2.4**
OECD (Nov 15)	**2**	**2.3**
Bank of Canada (Jan 2016)	**1.9**	**2.5**

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

Based on the discussion above, the Bank predicts that excess capacity will diminish, and that inflation will remain at 1.4% in 2015 and 2016, before increasing to 1.9%, close to its target rate in 2017. Their corresponding core inflation estimates for 2015-17 were 2.0%, 2.0% and 2.0% respectively. The Bank's total inflation projections were below, but in line with the Consensus forecasts, as well as with those of the IMF and OECD, all of which can also be found in Table 4.

TABLE 4
CPI FORECASTS – CANADA (2016-2017)

CPI Forecast	**2016**	**2017**
Conf. Board of Canada	1.6	2
CIBC World Markets	2	2.3
IHS Economics	2.1	2
Citigroup	1.8	2
BMO Capital Markets	1.7	1.9
Desjardins	1.5	2
Econ Intell Unit	1.8	2.2
EconoMap	1.6	2
Oxford Economics	1.6	1.9
JP Morgan	1.6	2
National Bank	1.7	1.6
RBC	2	1.8
TD Bank	1.5	1.9
University of Toronto	1.8	2.2
Scotia Econ	1.8	2.2
Informetrica	2.1	2
Average	**1.8**	**2**
Median	**1.85**	**2**
Max	**2.1**	**2.3**
Min	**1.5**	**1.6**
IMF (Oct 15)	**1.6**	**2.3**
OECD (Nov 15)	**2**	**2.3**
Bank of Canada (Jan 2016)	**1.4**	**1.9**

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

Of course, there are several uncertainties associated with the projections above. The Bank noted the following key risks to their inflation outlook, and suggested that these risks are "roughly balanced over the projection period": (1) lower potential output; (2) greater exchange rate pass-through; (3) lower oil prices and threshold effects; and (4) slower growth in emerging-market economies (EMEs).

The Bank acknowledges it is challenging to estimate the timing and impact of labour and capital allocations to non-commodity sectors. They suggest that they have focused on the low end of output and growth rates, and that the actual output gap could turn out to be below their estimates (i.e., if they were too conservative). As a result, they suggest that potential output represents a potential positive for economic growth, and hence a corresponding upside risk to inflation.

The Bank's estimate of the impact of past CAD depreciation of 0.7 percentage points to 2016 inflation may be on the low side, based on historical experience. Hence, if exchange rate pass-through exceeds this estimate, both economic growth and inflation will be higher, and the Bank judges this to be an upside risk to inflation.

If existing or future oil prices remain low or decline further, they may be below threshold levels for some oil firms to cover ongoing operating costs, which could further impact investment and employment in the industry. This would impact employment, as well as general confidence, and as such would represent a potential drag on economic growth, and hence a downside risk to inflation.

Weaker EME growth (e.g., China, Brazil, etc.) could be caused by several factors. If EME growth lags expectations, this could lead to reduced exports by the U.S., lower commodity prices, and/or increased market uncertainty. All of these outcomes would adversely affect Canada's economic growth prospects, and hence represent a downside risk to inflation.

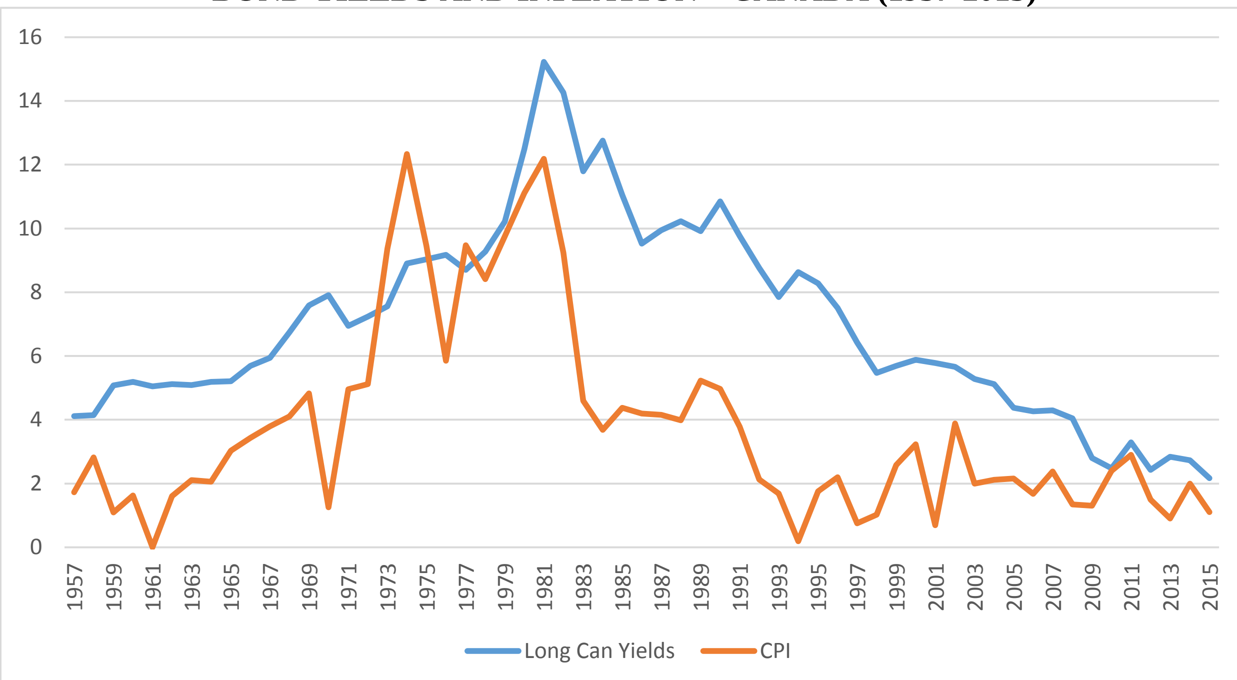
2.3 Capital Market Conditions and Expectations

2.3.1 Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 7 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation. Of course, yields are determined based on “expected” inflation, and we can see a few years in the 1970s where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since 1991 is obvious from the graph, with inflation hovering around the 2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 4.14%, with inflation averaging exactly 2.00%. Not only have long-term Canada yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005.

FIGURE 7

BOND YIELDS AND INFLATION – CANADA (1957-2015)

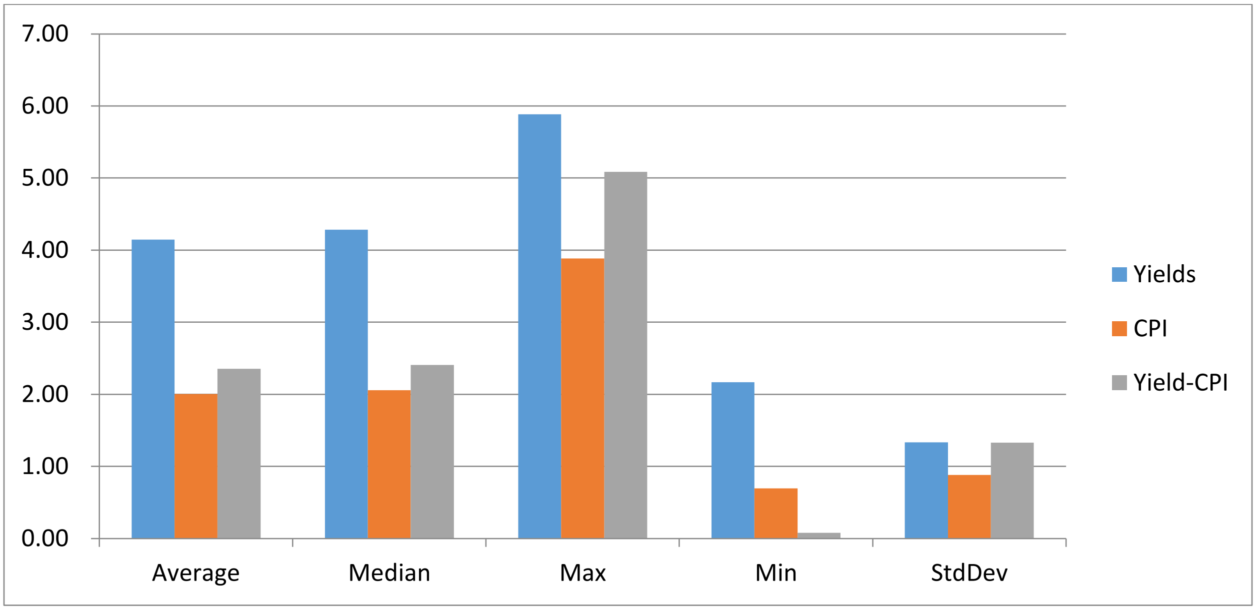


Data Source: CANSIM database.

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 7. This can also be seen in the standard deviations reported in Figure 8, which reports summary statistics for the 1998 to 2015 period. For example, the standard deviation of the yields was 1.34% over this period, versus 3.05% over 1957-2015. Figure 8 also shows that the difference between yields and inflation averaged 2.35% over the period, with a standard deviation of 1.33%. Combining these stats with long-term inflationary expectations of 2% suggests that long-term yields will gravitate towards 4.4% in the long-term, and under average conditions. Clearly, yields remain low today, but they are forecasted to increase, although they are expected to do so at a gradual pace over the next few years.

FIGURE 8

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2015)

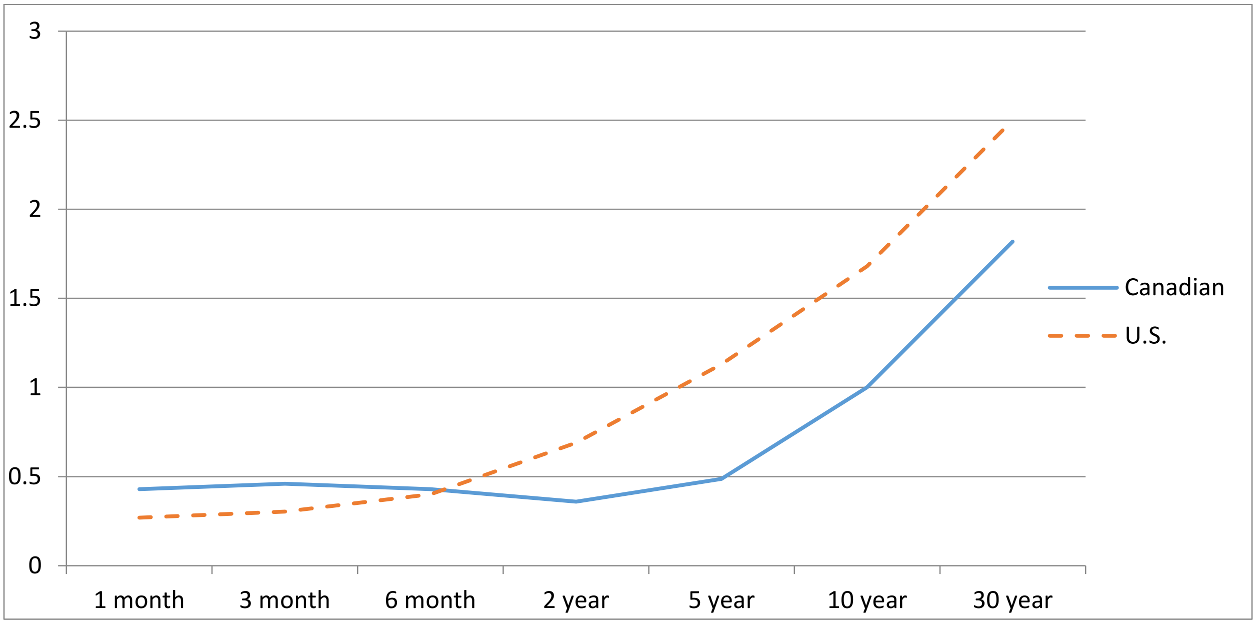


Data Source: CANSIM database.

Figure 9 depicts the yield curves for Canada and the U.S. as of February 9, 2016. We can see that U.S. rates for debt that matures within a year are very close to zero, while in Canada they are just below 0.5%. Aside from the extremely low levels, we observe the positive Canada-U.S. spread for short-term rates. However, when we look at the long end of the curve, we see that long-term U.S. rates exceed those in Canada (by 68 basis points).

FIGURE 9

YIELD CURVES – CANADA AND THE U.S. (JANUARY 14, 2014)

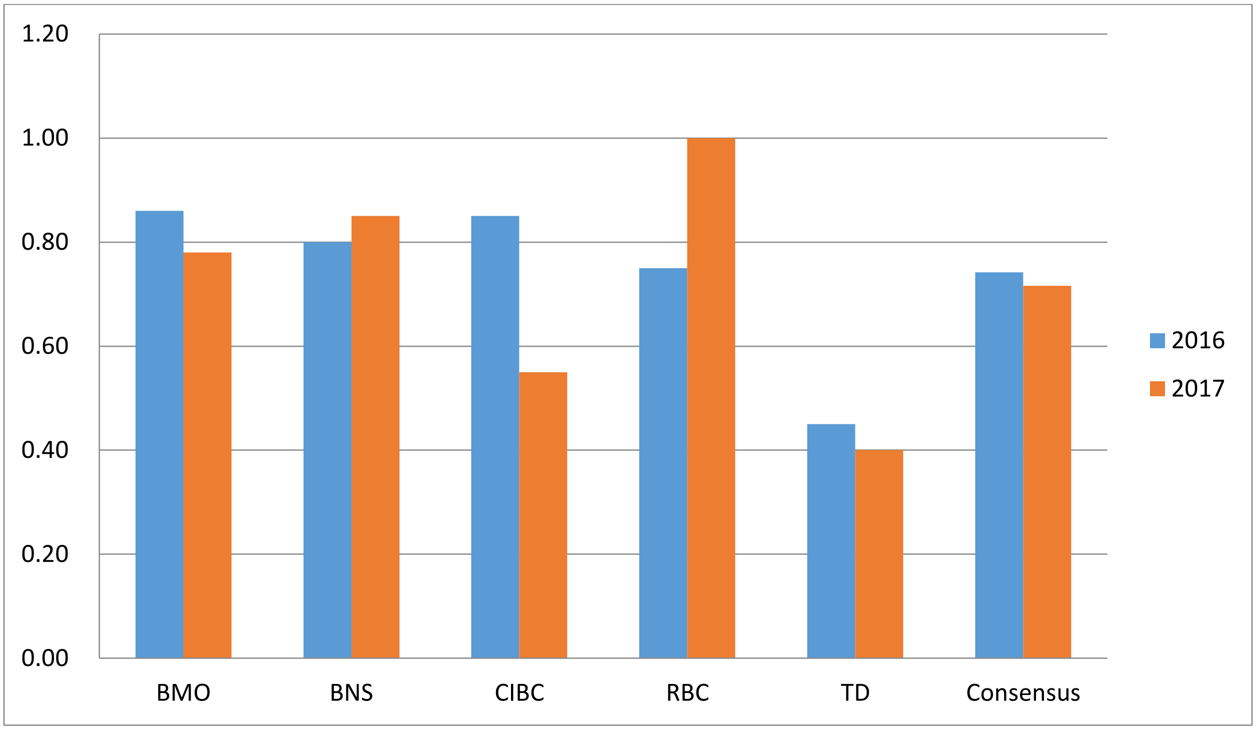


Source: Financial Post, February 10, 2016.

Figure 10 shows that Consensus Forecasts suggest that forecasters expect very little change in the current -68 basis point spread between Canada and U.S. 10-year bond yields, with only a slight widening to -74 basis points in 2016 and -72 basis points in 2017. This is also consistent with the beliefs of the Big Five Banks, which are also included in Figure 10.

FIGURE 10

PREDICTED U.S.-CANADA YIELD SPREADS – YEAR- END (2016-17)



Data Source: Various Bank Forecasts (2016) and Consensus Forecasts (January 2016).

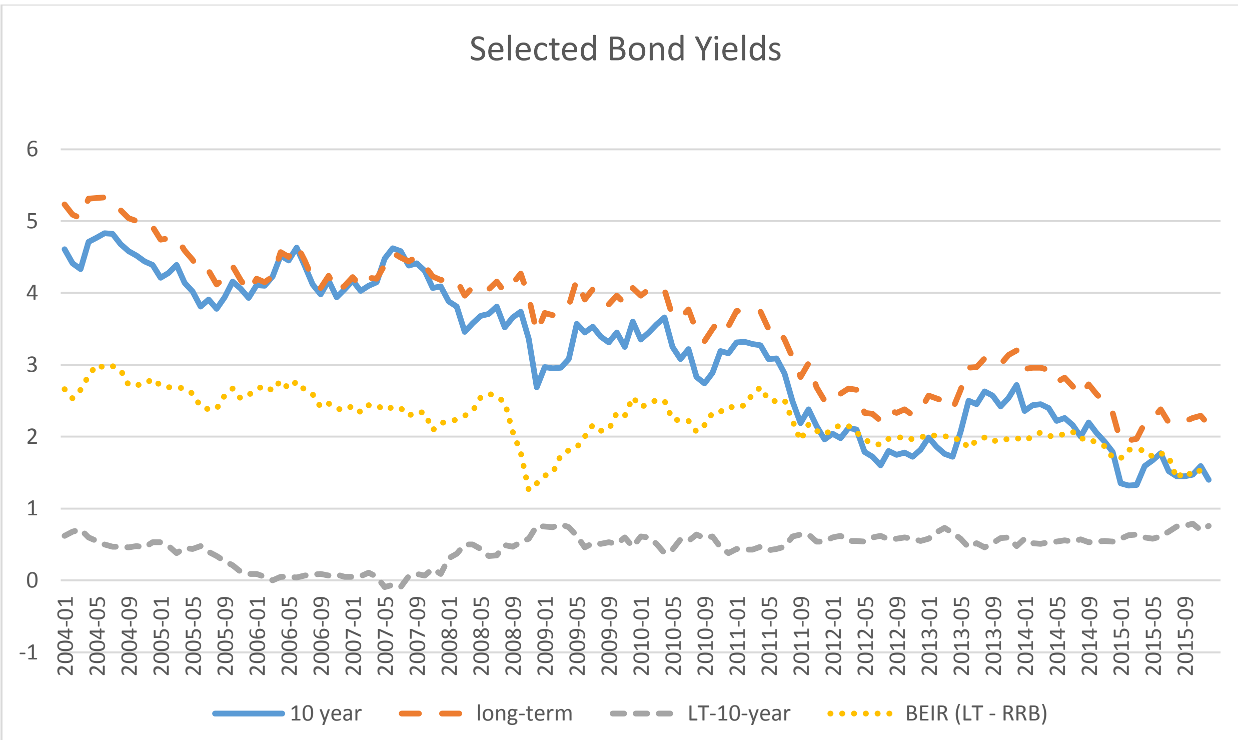
2.3.2 Interest Rate Levels

In light of recent levels of GDP growth and CPI, as well as their forecasted values in the immediate future, it is not surprising that interest rates in Canada have remained low over the most recent time period. Figure 11 shows 10-year and long-term bond yields in Canada over the last 12 years, which have moved in tandem for the most part, with a correlation coefficient of 0.98 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.46% (0.52%) over the entire period. It is obvious from the graph that this spread increased during the last half of 2015 and sat at 0.76% at the end of 2015, with long-term rates of 2.16% and 10-year rates of 1.40%. The graph also shows the break-even inflation rate (BEIR), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR can be viewed as an indicator of future inflation rates. This rate remained within the Bank’s target band for inflation over the entire period, peaking at

3.0% in 2004, hitting a trough of 1.26% in November of 2008 around the peak of the crisis, and averaging 2.2% overall, slightly above the Bank's target. It sat at 1.49% at the end of 2015, a mere 9 basis points above the Bank's CPI forecast for 2016, and 21 basis points below the Consensus CPI forecast.

FIGURE 11

SELECTED BOND YIELDS – CANADA (2004-2015)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Considering the discussion above, it is reasonable to assume that bond yields will increase, albeit slowly, in the coming months. This seems to be the consensus view of most economists in January of 2016, as can be seen in Table 5. The January 2016 Consensus Forecasts for 10-year Canada bond yields were 1.7% for the end of April 2016 and 2.1% for the end of January 2017 – up from the 2015 year-end value of 1.4%. If we assume the increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 1.75% for 2016, with a rate of 2.1% at the start of 2017. Assuming that the long-term average 50 basis point spread of 30-year yields over 10-year yields persists throughout 2016 and 2017, this implies long-term rates would increase from their 2015 year-end level of 2.16% for an average of 2.25% throughout 2016, and would lie at around 2.6% by January of 2017. The forecast averages for 3-month T-bill yields, which are not included in the table, were 0.5% for April 2016 and 0.7% for January 2017, little changed from current levels.

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2016-17)

10-Year Canada Yields	***Apr-16***	**Jan-17**
Conf. Board of Canada	*1.6*	2
CIBC World Markets	*1.6*	2.1
IHS Economics	*2.1*	2.3
Citigroup	*1.7*	1.8
BMO Capital Markets	*1.5*	1.7
Desjardins	*1.5*	1.9
Econ Intell Unit	*NA*	NA
Oxford Economics	*1.6*	1.8
EconoMap	*1.5*	1.7
JP Morgan	*NA*	NA
National Bank	*1.8*	2
RBC	*1.7*	2.4
TD Bank	*1.8*	2.1
University of Toronto	*1.6*	2.7
Scotia Bank	*1.5*	1.8
Informetrica	*1.8*	2.5
Average	**1.7**	**2.1**
Median	**1.6**	**2**
Max	**2.1**	**2.4**
Min	**1.5**	**1.7**

Source: Consensus Economics Inc. (January 2016).

It is reasonable to assume that as economic and capital markets gradually return to a more typical state that A-rated utility yield spreads will experience a gradual reduction from their current 2% level to around 1%. This 100 bps decrease would offset to a great extent by the expected increase in 10-year (and long-term) government yields of 70 bps during 2016, and another 40 bps in 2017. Of course, if some of the uncertainties identified earlier persist or get worse, these spreads may not return to normal levels, or may do so much slower than expected, so it is not a given. However, under such circumstances, it is unlikely that government yields would increase as much as expected – so changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent.

2.3.3 Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 6 reports summary statistics for Canadian capital markets over the 1938 to 2015 period.

TABLE 6

CAPITAL MARKET SUMMARY STATISTICS – (1938-2015)

1938-2015 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (CAD)
Average	3.77	11.31	6.62	4.80	12.69
Median	2.84	11.08	4.26	3.86	12.50
Std. Dev.	3.43	16.49	9.15	4.24	17.55
Geo. Mean	3.70	9.78	6.23	4.67	11.42

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM.

The long-term average return in the Canadian stock market over this period was 11.3%, with a geometric mean of 9.8%. This occurred over a period in which inflation averaged 3.8% (geometric mean of 3.7%). This implies "real" returns of approximately 7.5% (6.1%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.1% to 9.5% going forward. These numbers are consistent with current estimates of expected stock returns going forward. For example, in its January 7, 2016 report on capital market assumptions, AON Hewitt estimated an expected average annual return on Canadian equities for the next 10 years of 8.3%, with an associated expected 10-year compound return (i.e., geometric mean) of 7.1%.[5] Based on an expected long-term government bond yield of 2.2% in 2016 and 2.7% in 2017, expected stock market returns of 7.1% to 8.3% imply market risk premiums (MRPs) in the 4.4% to 6.1% range. The mid-point of this range is 5.25%, which is slightly above the long-term historical average of approximately 5%, while the range itself is in line with the usual 4-6% range for MRP estimates.[6]

Investors have adjusted their expected returns down in line with lower inflation expectations, and the lower bond returns that are associated with lower inflation expectations (as shown previously). The 7.1% to 8.3% range for expected stock market returns is slightly above average figures currently used by many actuaries which are closer to 7-7.5% according to a recent Financial Post article.[7] Similarly, a December 2012 Educational Note prepared by the Canadian Institute of Actuaries suggests that the best long-term Canadian equity return estimate would be 7% if the long-term government yield was 4% (advocating the use of a 3% MRP).[8] U.S. estimates are similar, as noted in an October 2012 report prepared by the U.S. Society of Actuaries. [9] This report produced a range of long-term U.S. equity annual return estimates from 4.6% to 8.0%, and averaging 6.3%, using a variety of approaches. Finally, an interesting study

[5] Source: Aon Hewitt Capital Market Assumptions & Methodology (Canadian Version), Aon Hewitt, January 7, 2016.
[6] Greater discussion of the market risk premium will follow in the section dealing with the CAPM analysis.
[7] This article suggests using a 5.25% real return plus 2.25% for expected inflation for forecasting domestic stock returns: "Calculating investment returns: Actuarially speaking 6% is a good rule of thumb," Fred Vettese, http://business.financialpost.com/2013/09/21/calculating-investment-returns-actuarially-speaking-6-is-a-good-rule-of-thumb/, January 24, 2014.
[8] Source: "Determination of Best Estimate Assumptions for Investment Return (PPICP)," Educational Note, Canadian Institute of Actuaries, Document 212106, December 2012.
[9] Source: "Estimating Equity Returns," Victor Modugno, Sponsored by Society of Actuaries' Pension Section Research Committee, Society of Actuaries, October 2012.

on this issue was recently conducted by the C.D. Howe Institute.[10] They predicted long-term nominal equity returns of 6.9% and long-term bond returns of 2.5% (partially due to the expectations of increases in bond yields). Combining these two results they concluded an expected return of 4.7% on pension plans with a 50/50 weighting in stocks and bonds. While not all plans will maintain such an asset mix, they compare this figure to the projected average annual return of 6.9% determined in the 2012 Towers Watson survey of pension funds and conclude that many of the pension fund managers are overly optimistic.

The stock market return estimates above are well below long-term geometric nominal mean stock returns of 9.8% (over 1938-2015), but are consistent with lower expected bond returns in the future (i.e., below their 1938-2015 geometric mean return of 6.2%). These long-term stock and bond returns occurred during a period where the geometric mean of inflation was 3.7%, implying real returns on stocks and bonds of 6.1% and 2.5%. It is easy to see that adding a current expected future inflation rate of 2% to these figures, provides "simple" long-term estimates of 8.1% and 4.5%. I believe it is important to carefully consider such "consensus" return expectations with respect to the long-term. As mentioned, making stock market predictions for any given year is very difficult. However, long-term expectations of the majority of investment professionals play a big role in determining overall market expectations, and hence in determining required rates of returns by investors. These required returns on the average stock in the market will in turn influence the returns that investors will require on utilities, which plays a big role in determining what represents a reasonable allowed ROE. If overall market return expectations are in the 7% to 9% range, as the evidence supports, this implies that investors will be satisfied with return expectations below these numbers for low-risk regulated utilities. In other words, a reasonable required rate of return for utilities should be below the mid-point of the range of overall market expectations of 8%.

[10] Source: "Long-Term Returns: A Reality Check for Pension Funds and Retirement Savings," R. Guay and L.A. Jean, Commentary No. 395, C.D. Howe Institute, December 2013.

2.4 Oil Prices

Given the importance of oil prices to the Canadian economy, and the Alberta economy in particular, a brief discussion of oil prices is warranted. Figure 12 depicts crude oil prices from 2006 to February 2, 2016.

FIGURE 12

Crude Oil Prices (2006-February 2016)

Source: *Investor Literature Review 2016(3)*, “Oil Update,” February, 2016.

Predicting the timing and exact levels of oil prices is challenging (which is why the Bank of Canada does not provide any such formal forecasts). However, the general consensus is that they will increase in the future – of course the debate is to how much and how fast they will increase. For example, Mr. Buttke provides Bloomberg estimates of $38.26 by Q4 2016, $40.93 by 2017, $44.20 by 2018 and $46.71 by 2019. In its February 2016 review, Investor Literature reviewed a January 4, 2016 article by AB Bernstein and noted “While Bernstein’s WTI price increase estimates quoted above were for $48, $68, $78 in 2016, 2017, 2018, these are not far off the consensus estimates we discuss below which for WTI are reported to be: $51, $60, $66 in those same years."[11] The Investor Literature review also reviewed a February 4, 2016 Globe and Mail article which suggested oil prices would be in the $46-48 range by the end of 2016 according to a survey of 17 oil analysts. Given the difficulties in predicting future oil prices, I merely report these estimates and note that the consensus is that they will increase eventually, and I would also note that oil had rebounded to $38.50 by March 11, 2016.

2.5 The Alberta Economy

Unfortunately, Alberta is one of the provinces affected most negatively by the recent decline in oil and commodity prices. In Q3 2015, the Alberta Treasury Board and Finance estimated real GDP growth for Alberta of -1.5% in 2015 and -1.1 percent in 2016.[12] Recent estimates indicate a better outlook for Alberta in 2016. For example, Table 6 on page 13 of Mr. Buttke's evidence indicates Bloomberg forecasts for Alberta GDP growth at +1.0 percent in 2016, and +3.0 percent in 2017. The Conference Board of Canada (CB) 2015 fall provincial outlook estimated GDP growth of -1.2% in 2015, +1.2% in 2016, and +2.2% in 2017. So there appears to be general agreement that the economic growth will be slow but improving for Alberta in the short term.

As the Conference Board notes in its fall provincial outlook, the Alberta economy has been hit hard by falling oil prices leading to reduced investment by energy companies, which has also affected government revenues, employment rates, and consumer spending. They note two positive contributors to economic growth – increased bitumen exports to the U.S. and infrastructure spending by the government.

Over the next two years, the CB expects energy investment and the domestic economy to remain weak before oil prices bounce back in the later part of 2016 and through 2017-18. As a result, they forecast the unemployment rate to increase from 5.9% in 2015 to 6.7% in 2016, before declining to 6.1% in 2017, and then to the 4-5% range in 2018-2020. Similarly, the CB expects household disposable income will increase moderately in 2016 (at +1.5%) before increasing at an

[11] Source: Investor Literature Review 2016(3), "Oil Update," February, 2016.
[12] Source: http://www.alberta.ca/budget-economic-situation.cfm, February 24, 2016.

annual rate of 4.0% in 2017, and at rates above 4% in 2018-2020, as can be seen in Table 7. The CB's 2016-2020 real GDP growth forecasts of +1.2%, +2.2%, +2.0%, +2.6% and +2.8% respectively are reflective of these factors.

Finally, it is interesting to note that the CB expects the contribution to Alberta GDP from the utilities sector to remain positive in 2016-17 (+3.3% and +3.0% respectively), and also in the ensuing three years (2.9%, 2.7%, and 1.9% respectively). This is consistent with the low risk nature of utilities such as the Alberta utilities, whose demand is less cyclical than most industries.

TABLE 7

CONFERENCE BOARD OF CANADA ECONOMIC FORECASTS FOR ALBERTA - 2015-2020

ALBERTA

Growth (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Real GDP	-1.2	1.2	2.2	2.0	2.6	2.8
CPI	1.3	2.6	2.3	2.1	3.0	2.0
Household Disposable Income	1.7	1.5	4.0	4.1	4.6	4.4
Employment	1.4	0.5	1.5	1.8	1.9	1.2
Unemployment Rate	5.9	6.7	6.1	5.2	4.5	4.2
Utilities Sector GDP Contribution	2.7	3.3	3.0	2.9	2.7	1.9

3. ROE CALCULATIONS

3.1 Capital Asset Pricing Model (CAPM) Estimates

This section employs the commonly used Capital Asset Pricing Model (CAPM) to estimate the allowed return on equity (ROE) for the average Alberta utility. Essentially CAPM can be used to estimate the required return on equity (Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

$$Ke = RF + (ERm – RF) Beta$$

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of Financial analysts[13]
- by over 70 percent of U.S. CFOs[14]
- by close to 40 percent of Canadian CFOs[15]

Of course, the CFOs are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous Decisions, which is appropriate in my opinion.

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate risk-free rate, since it is virtually guaranteed and does not fluctuate. However, analysts often use the CAPM to estimate the required return on common equity over many periods, such as when they are trying to estimate the cost of a firm's common equity financing component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are

[13] Source: Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute.
[14] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243.
[15] Source: H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: where do we stand" Multinational Finance Journal 15-3, 2011.

more representative of the rate that could be obtained over longer investment horizons. This is practice is consistent with previous Decisions.

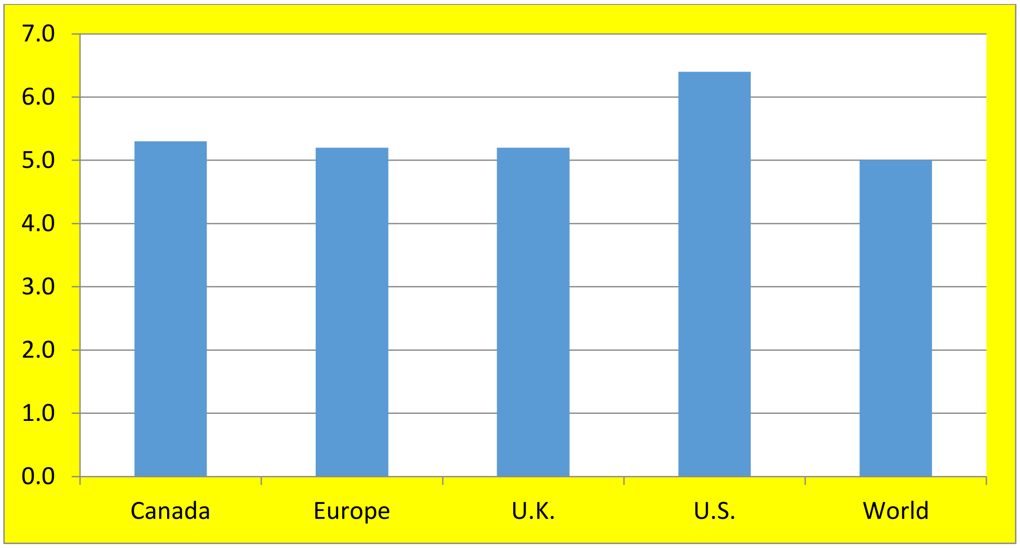
I estimate RF using the approach used by the Commission as described in paragraph 93 on page 19 of its 2013 GCOC Decision. In particular, the January 2016 Consensus Economics forecasts for government 10-year yields are 1.7% for April 2016 and 2.1% for January 2017. Adding the long-term average spread between 10- and 30-year government yields of 50 basis points to these forecasts, implies forecasted 30-year government bond yields of 2.2% and 2.6% respectively. So 2.6% will provide the upper limit of my RF estimate range. I will round up the actual prevailing long-term government yield as of February 2016 of 1.94% to 2% and use it as my lower bound. This gives me a range of 2.0-2.6% for my 2016-17 RF estimate, with a mid-point of 2.3%.

The market risk premium (MRP), as measured by the return on the market less the long-term government bond yield over the 1900-to-2010 period, averaged about 5 percent in developed stock markets around the world, which is lower than the U.S. and Canadian averages, over that period, of 6.4 percent and 5.3 percent, respectively.[16] These figures can be seen in Figure 13. The figure for Canada is close to the difference in average returns for stock and bond returns over the 1957 to 2013 period of 4.9% as previously reported in Table 6. These numbers are also consistent with the expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6 percent range for most regions. The results for Canada and the U.S. are reported in Figure 14.

FIGURE 13

GLOBAL MARKET RISK PREMIUMS (1900-2010)

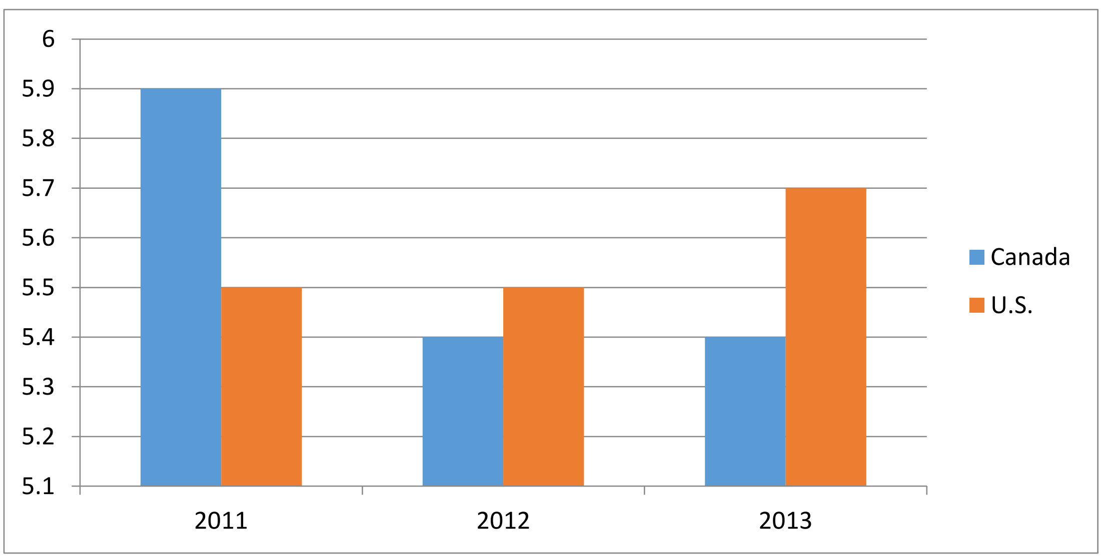
[16] Dimson, Elroy, Marsh, Paul, and Staunton, Mike, "Equity Premiums Around the World," in *Rethinking the Equity Risk Premium* (Research Foundation of the CFA Institute, December 2011).



Source: Dimson, Marsh and Staunton, "Equity Premiums Around the World," in _Rethinking the Equity Risk Premium_, CFA Institute, 2011.

FIGURE 14

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2011-2013)



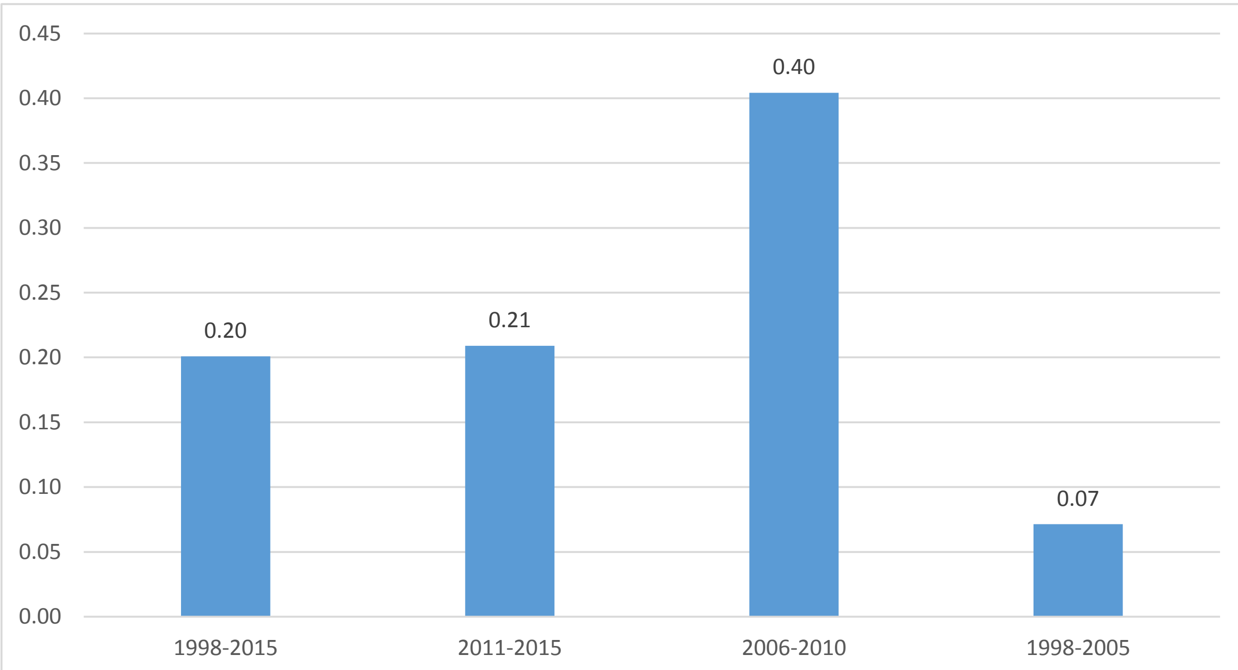
Source: "Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers," 2013, by Pablo Fernandez, Javier Aguirreamalloa, and Pablo Linares,
Working Paper, IESE Business School.

Based on the previous discussion of capital markets, I concluded that stock markets reflect fairly normal conditions, but are experiencing slightly more volatility than at the time of the 2013 Hearings. Therefore, I will use an MRP of 6%, which is at the upper bound of the commonly used 4-6% range, 70 basis points above the long-term average of 5.3%. This seems appropriate in today's environment, where economic and market conditions are fairly normal in terms of valuation metrics like P/E ratios and dividend yield measures. This is consistent with the practice of using 6 percent when market uncertainty is above average, using 5 percent when markets are normal, and using 4 percent during periods of extreme market and economic optimism. These estimates are also consistent with previous Decisions by the AUC. For example, the AUC used an MRP range of 5-7% in 2013 and 5.0-7.25% in 2011.

We now require a beta estimate to apply the CAPM. In its 2013 and 2011 Decisions, the Commission used a range of 0.50 to 0.65 for the average utility beta, very similar to the 0.50-0.63 range it used in 2009. Dr. Booth used the same of 0.45-0.55 range as in his 2009 testimony, which he based on long-term average beta estimates for Canadian utilities, going back to the mid-1980s. This suggests very clearly that unless conditions have changed significantly for utilities, long-term data as well previous Decisions (which are consistent with this data) support the use of betas in the 0.45 to 0.65 range. My own research below suggests that this is reasonable; but that current betas are below the lower bound of this range. For example, Figure 15 reports the average betas calculated using monthly total return data for the TSX Utilities Index over the 1998 to 2015 period. The first reported beta estimate uses data for the entire 18-year period and is 0.20. The remaining betas are for distinct five-year periods (with the exception of the use of eight years of data for the 1998-2005 estimate), which is a commonly used time horizon for estimating betas with monthly data. The graph shows that betas for utilities have been in the 0.2 to 0.4 range, aside from the 1998 to 2005 period where betas for many industries, including utilities, were not meaningful due to the high technology boom and bust during that period. In the last two sub-periods, we see that the recent utility index beta has been between 0.2 and 0.4, below the long-term average of 0.5, and at the lower end of the typical range used for utilities.

FIGURE 15

BETA ESTIMATES FOR THE CANADIAN UTILITY INDEX (1998-2015)



Data Source: CHASS database.

Table 8 provides beta estimates for several Canadian utilities as of February 9, 2016, based on 60 months of returns. The average is 0.21, slightly above the 0.19 Utilities Index estimate over the 2011-2015 period provided in Figure 13. The average decreases slightly to 0.19 if we drop TransAlta and Northland, which are primarily non-regulated utilities. If we also exclude Canadian Utilities Ltd. and ATCO, which are holding companies that include interests in non-regulated assets, and we also exclude Algonquin, which also has a mix of regulated and non-regulated assets, then the average declines further to 0.16.

TABLE 8

BETA ESTIMATES – FEBRUARY 2016

Firm	**Beta**
Fortis	0.03
Emera	0.02
TransAlta	0.46
Northland Power	0.09
Algonquin Power	0.23
ATCO	0.39
Cdn Utilities Ltd.	0.05
Enbridge	0.22
TransCda	0.36
Average	0.21
Average excl. TransAlta and Northland	0.19
Average (Fortis, Emera, Enbridge, TransCda)	0.16

Source: FP Infomart, February 9, 2016.

Based on the evidence in Figure 13 and Table 8, and combining with long-term evidence provided in previous decisions, it seems clear that a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. I will use the mid-point figure of this range of 0.45 as my best point estimate, which is slightly below the long-term average of around 0.50.

Government bond yields remain low by historical standards, and A-rated Canadian utility bond yield spreads are sitting at about 200 basis points today, about 100 basis points above the long-term average spread. While this spread is not anywhere near the record highs experienced during the financial crisis, it is still indicative of slightly heightened risk aversion. Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian Utilities.[17] Consistent with this research, I will add half of the "above average" yield spread or 0.50% to my CAPM estimate to account for this time varying risk premium.

Finally, I add 50 basis points for financial flexibility (or flotation costs), which has been used in previous decisions, and is consistent with long-term estimates. Combining these items we get the following range of estimates for the required equity return for an average utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests that 6% is a reasonable ROE (in the 4.27.5% range).

[17] Refer to: A. Garcia and J. Yang, "Understanding Corporate Bond Spreads Using Credit Default Swaps," Bank of Canada Review, Autumn 2009.

TABLE 9

CAPM ESTIMATES – 2016-2017

Estimate	**RF (%)**	**MRP (%)**	**Beta**	**Spread Adjust. (%)**	**Financial Flex. (%)**	**Ke (%)**
Max	2.6	6.5	0.60	0.50	0.50	7.50%
Min	2.0	5.5	0.30	0.00	0.50	4.15%
Best Estimate	2.3	6.0	0.45	0.50	0.50	**6.00%**

The CAPM parameters used (i.e., RF of 2.3%, MRP of 6% and the spread adjustment of 0.5%) imply a required return on the market of 8.8%, which is at the high end of market expectations, and close to the long-term real return on stocks. The 6.0% estimate is at the lower end of the range of CAPM estimates of 5.8-8.75% used by the Commission in its 2013 Decision. Ultimately, the driving force behind these lower estimates is the fact that long-term government bond yields (RF) turned out to be much lower than anticipated during 2015, and remain low in early 2016. This in turn has enabled A-rated Canadian utilities to benefit by issuing long-term debt at historically low yields, which hit a minimum of 3.3% in February 2015, and which currently sit at around 4%. Therefore it makes sense that the cost of equity has also decreased since bond and stock markets are inter-related as acknowledged by the Commission in its 2013 Decision (pages 18-19, paragraph 90):

> "The Commission agrees with Dr. Cleary's view that "the equity markets pay very close attention to what's available on the bond markets and *vice versa*." In circumstances where sovereign and commercial borrowers are able to borrow at historically low rates, the Commission does not accept that a CAPM analysis should be based on a "normalized" risk-free rate of 4.0 per cent, which represents what *should* have been in place to reflect investor risk-return expectations. As Dr. Cleary pointed out, "you think of how an investor thinks, they think about what I can earn on a bond today. The fact that it should be 4 percent isn't – it's nice to know but it is 3 percent.""

3.2 Discounted Cash Flow (DCF) Estimates

There has been much debate in previous Decisions regarding the usefulness of DCF approaches. In particular it has been questioned:

- whether or not it even made sense to apply the approach at the company/industry level – given the lack of a sufficient number of representative "pure-play" regulated utility companies in Canada; and,
- how to infer DCF results when they are made at the "market" level rather than for companies.

Despite this debate, the parties involved have provided various forms of DCF estimates. The Commission has taken this information into account in making their final ROE decisions, recognizing that the estimates provide some informational value, while recognizing some of the approach's limitations. As such, I am going to take two approaches and apply DCF approaches as at the start of 2016 to:

1) find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the "average" company in the market; and,

2) apply the models at the industry level using numbers that are "representative" of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The Dividend Discount Model (DDM) is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely. The constant-growth model can be represented as:

Price = $D_0(1 + g) / (Ke – g) = D_1/(Ke – g)$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/\text{Price}) \times (1 + g) + g$$

Table 1 showed that real GDP growth averaged 3.3% over the 1962 to 2014 period. This seems a reasonable growth rate to use in the single-stage model, since we would expect long-term growth for the overall market to gravitate towards this figure – this assumption is commonly made by financial analysts. Of course, we are trying to estimate a "nominal" required rate of returns, so we should use nominal GDP growth as "g." If we apply the 2% Bank of Canada inflation target (also the median inflation rate over the 1992-2014 period) to this real rate of growth we get the following estimate of g: g = (1.033)(1.02) – 1 = 0.054 or 5.4%.

This growth rate is line with those used by security analysts when they use single-stage growth models to value securities; albeit slightly on the high side (i.e., they usually use numbers in the 3-5% range "when" they use single period models).

The dividend yield for the S&P/TSX Composite Index as of February 2016 was 3.4% - this is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent

12-month period. Substituting these estimates into the equation above, we get the following estimate for the implied equity return for the market as a whole for 2016:

Ke = (D0/Price)×(1 + g) + g = (0.034)×(1.054) + .054 = 0.0358 + .054 = .0898 or 8.98%

Table 1 also showed that average real GDP growth has been lower at 2.6% since 1992. We could use this as a lower bound and repeat the process. This would imply a long-term nominal growth rate of 4.65% (i.e., [1.0260 × 1.02] – 1). Substituting this growth rate into the Ke equation, and using the same dividend yield, we get: Ke = (0.034) ×(1.0465) + .0465 = 0.0356 + .0465 = .0821 or 8.21%.

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, these seem to be reasonable estimates; albeit slightly high. They are at the upper half of forecasts of future returns that were discussed earlier in the 7-9% range, and are consistent with my CAPM market estimate of 8.8% and with long-term "real" stock return averages in the 6.1-7.5% range also noted previously.

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

The H-Model has great appeal today, if we consider that the Consensus Real GDP Growth forecasts for 2016 and 2017 as reported in Table 3 are 1.7% and 2.2% respectively, while the corresponding inflation forecasts were 1.8% and 2.2%. If we combine these average figures to estimate expected nominal GDP growth rates for 2016-2017 we get 3.53% and 4.24%

respectively. This suggests that expected GDP growth is currently below the 5.4% long-term level used previously, but that it can be expected to gradually return to such levels.

I will apply the model as of the beginning of 2016, using the estimated 2016 nominal GDP growth rate of 3.53% as g_S and the long-term expected growth rate of 5.4% as determined above for g_L. Assuming it takes us four years to get back to this long-term expected growth rate, I use H = 2, which provides an estimate for Ke of 8.85%. If we assume that this return to normal growth takes only two years, so that H = 1, we get an estimate for Ke of 8.92%.

Combining the results from the two models, we get estimates for Ke for the market in the 8.2-9.0% range. I will use the mid-point of the average estimate of 8.6% from the single-stage DDM and 8.9% using the H-model to arrive at 8.75% as my best estimate of the implied return on the market using DCF models. This number is slightly on the high side, but not unreasonable, as it lies at the upper end of the range market expectations. It is consistent with historical real returns on stocks and with my CAPM estimate for the market of 8.8%. As noted previously, while DCF models will work better in aggregate than for Canadian utilities, we are still left with the issue of how to adjust these figures into a reasonable implied return for utilities, which possess considerably less risk than average. At minimum, we could say that market DCF estimates above suggest that utility returns should be lower than 8.75%.

I will now apply both of the DCF models discussed above to Canadian utilities. Of course determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's sustainable growth rate**,** which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the return on equity (ROE), as shown below:

g = (1 – payout ratio) × ROE.

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures.

Table 10 below includes summary statistics on dividend yield, payout ratios and ROE for the 9 Canadian utility firms included in Table 8. These data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using our two DCF models. Panel A reports the average, median, maximum and minimum figures for all 9 utilities for the February 2016 dividend yield (DY), the average 5-year DY, the 2014 payout ratios and ROEs, and the 2006-14 averages for payout and ROE.[18] Panel B reports the same statistics after eliminating TransAlta and Northland, and Panel C after also eliminating ATCO, Canadian Utilities, and Algonquin.

[18] Payout ratios were "capped" at 100% to control the influence of extreme payouts on "averages" - this process obviously had no effect on the reported medians.

TABLE 10
DCF INPUT ESTIMATES – 2006-2014 FIGURES

	DY (Feb 16)	5-year Avg DY	2014 Payout	Avg Payout (06-14)	2014 ROE	Avg ROE (06-14)
Average	4.86	4.19	73.04	65.43	7.64	9.64
Median	3.90	3.96	79.00	62.43	10.40	9.71
Max	14.40	4.91	100.00	76.84	17.00	12.58
Min	2.50	3.78	24.20	58.34	-17.95	5.21
Average (excl TransAlta and Northland)	3.83	3.34	73.04	60.61	11.49	11.44
Median	3.90	3.22	79.00	59.71	12.39	11.49
Max	4.60	3.88	100.00	72.49	17.00	14.33
Min	2.60	3.01	24.20	47.59	5.45	9.91
Average (Fortis, Emera, Enbridge, TransCda)	4.03	3.59	86.65	70.95	11.31	11.70
Median	4.05	3.45	86.40	64.15	11.40	12.08
Max	4.30	4.06	100.00	87.03	17.00	13.50
Min	3.70	3.20	73.80	60.33	5.45	9.03

Data Source: Morningstar at www.morningstar.ca.

The summary statistics included above appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. Payout ratios between 60% to 80%, and gravitating toward an average of 70%, are in line with historical figures and also with the high dividend paying nature of such profitable, slow growing firms. Similarly, dividend yields in the 4-5%

range are in line with that of the S&P/TSX Utilities Index, which was 5.2% as of February 19, 2016. The ROE numbers in the 8-12% range are similarly in line with 2009-2014 figures reported by the 11 Alberta utilities in their recent Rule 005 reports, as can be seen in Table 14 in Section 3.6. Table 14 shows that the average ROE across all Alberta utilities and across all years averaged 9.4%, with the 11-firm average remaining in the relatively narrow range of 8.8% in 2011 to 9.9% in 2009.

U.S. utilities are not the best comparators to Alberta utilities for a variety of reasons, as noted in previous Decisions. For example, in the 2004 Decision, in consideration of U.S. evidence, the Board concluded that "limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries." This Decision was upheld after lengthy discussion on the issue in the 2009 proceedings, and the underlying principle was applied in the 2011 Decision by applying minimal weights to U.S. evidence. I also provide compelling empirical evidence in Section 4 that shows that U.S. utilities have significantly more business risk than their Canadian counterparts. Nonetheless, the Canadian numbers reported in Table 10 are within range of typical U.S. figures. For example, over 2008-2012, the average payout ratio for the 50 firms included in the S&P 1,500 index group was 66.15%. Over the same period, the average dividend yield high-low range was 5.22-3.58%, with an average mid-point of 4.4%.

As mentioned it is difficult to find "typical" or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 11 provides estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 10. These are calculated using the formula above (i.e., g = (1 – payout) × ROE). Column 2 uses the average and median ROE and payout figures for 2014, while column 3 uses the averages over the 2006 to 2014 period. The median and average growth rates range from 1.51% to 4.63%, but are generally in the 2-4% range. This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth.

TABLE 11

SINGLE-STAGE DDM ESTIMATES Ke Estimates	**Implied g (2014)**	**Implied g (06-14)**	**Implied Ke (2014 and 2016 DY)**	**Implied Ke (06-14 and 5-year avg. DY)**
Average	2.06	3.33	7.02	7.66
Median	2.18	3.65	6.17	7.75
Average (excl TransAlta and Northland)	3.10	4.51	7.04	8.00
Median	2.60	4.63	6.60	8.00
Average (Fortis, Emera, Enbridge, TransCda)	1.51	3.40	5.60	7.11
Median	1.55	4.33	5.66	7.93
Average of 6 averages Ke = 7.07%				
Average of 6 medians Ke = 7.02%				

The final two columns in Table 11 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 10). Recall this formula can be represented as follows, when we begin with the dividend yield based on dividends over the previous 12 months: Ke = $(D_0/\text{Price})\times(1 + g) + g$.

These estimates range from a low of 5.60% using 2014 average numbers and considering only Fortis, Emera, Enbridge and Trans Canada, to a high of 8.00% using 2006-14 average or median values after excluding Transalta and Northland. As mentioned, it is difficult to determine which group provides the most representative statistics, so it is useful to determine the average of all these estimates. The average of all 6 Ke estimates determined using averages is 7.07%, while the average of the 6 numbers calculated using the medians is 7.02%. This provides us with a reasonable range of estimates using the single-stage growth DDM. I will assign a "best estimate" in the middle at 7.04%. This estimate is below the 8.75% estimate for the market, which is reasonable since regulated utilities are considerably less risky than average. If we add 50 basis points for flotation costs, we end up with a range of 6.1%-8.5%, with a best estimate of 7.54%.

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the implied growth rates determined using 2014 payout ratios and ROEs, which are reported in column 2 of Table 11. I then denote as g_L the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 11. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 12 below.

TABLE 12

H-MODEL ESTIMATES

Using all 9 Utillities		
	H=2	**H=1**
Current D0/P0	0.0486	0.0486
gs (current sustainable g)	0.0206	0.0206
gL (5-year sustainable g)	0.0333	0.0333
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0206	0.0206
g1	0.0238	0.0270
g2	0.0270	0.0333
g3	0.0301	0.0333
g4	0.0333	0.0333
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	0.0822	0.0829
Excl TransAlta and Northland		
Current D0/P0	0.0383	0.0383
gs (current sustainable g)	0.0310	0.0310
gL (5-year sustainable g)	0.0451	0.0451
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0310	0.0310
g1	0.0345	0.0380
g2	0.0380	0.0451
g3	0.0416	0.0451

g4	0.0451	0.0451
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	0.0840	0.0846
Fortis, Emera, Enbridge, TransCda		
Current D0/P0	0.0403	0.0403
gs (current sustainable g)	0.0151	0.0151
gL (5-year sustainable g)	0.0340	0.0340
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0151	0.0151
g1	0.0198	0.0245
g2	0.0245	0.0340
g3	0.0293	0.0340
g4	0.0340	0.0340
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	0.0741	0.0748
AVERAGE	**0.0801**	**0.0807**

The Ke estimates lie within the range of 7.4% to 8.5%. The average estimate is 8.01% if we assume a 4-year transition in growth rates (i.e., H =2), and is slightly higher at 8.07% if we assume a 2-year transition. Combining these results with a 0.50% allowance for flotation costs, we get the following ranges and point estimates: 7.9-9.0% with a best estimate of 8.54%. The Ke estimates from the H-Model are higher than the averages derived using the single-stage model. This is because the model implicitly assumes that growth rates will gravitate to longer term average rates, which were higher than the implied rates using 2014 data only. I weight the estimates from the constant-growth model and the H-Model equally in arriving at my final DCF estimates.

A summary of the DCF estimates determined above is provided in Table 13 for the market and for Alberta utilities. The DCF analysis suggests an 8.75% required return on the market with a range of 8.2-9.0%. As discussed previously, this estimate is in line with my CAPM estimate of 8.8% and with long-term real stock returns, and sits at the high end of current market estimates. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return with a range of 6.1-9.0% and a best estimate of 8.04%. This estimate is 1.21% below the DCF estimate for the market (if we also adjusted the market estimates 50bps for flotation costs), which is consistent with the below-average risk of utilities.

TABLE 13

DCF ESTIMATES

Year	Model	Minimum	Maximum	Best Estimate	Flotation Costs Adj.	Range	Final Estimate
Panel A: Market Estimates							
	Single-Stage	8.21	8.98	8.6	0.50	8.7-9.5	9.1
	H-Model	8.85	8.92	8.9	0.50	9.35-9.42	9.4
	Combined	8.21	8.98	8.75	0.50	8.7-9.5	**9.25**
Panel B: Utility Estimates							
	Single-Stage	5.6	8.0	7.04	0.50	6.1-8.5	7.54
	H-Model	7.4	8.5	8.04	0.50	7.9-9.0	8.54
	Combined	5.6	8.5	7.54	0.50	6.1-9.0	**8.04**

3.3 Bond Yield Plus Risk Premium (BYPRP) Estimates

The bond yield plus risk premium (BYPRP) approach adds a risk premium (generally in the 2-5% range) to the yield on a firm’s outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. It is depicted below:

Ke = Company’s Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[19] and by over 50 percent of Canadian CFOs.[20]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable *market-determined* bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

This approach provides useful reasonableness checks on CAPM and other estimates, and employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s. In fact, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta.

The first step is to obtain an estimate of the cost of long-term yields on a typical utility. As of February 3, 2016 the yield on long-term A-rated Canadian utility bonds was 4.03% according to the Bloomberg data used to construct Figure 3. This number is close to the yields on outstanding Canadian utility bonds at the time – for example the yield on Canadian Utilities Inc. bonds maturing in September 2044 was 3.99% on February 5, 2016, while the yield on Hydro One bonds maturing in June 2044 was 3.97%. This implies that 4.03% is a reasonable starting point for my BYPRP estimate.

[19] Source: Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute.
[20] Source: H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: where do we stand" Multinational Finance Journal 15-3, 2011.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for "average" risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of 2.5%. Combining this information, I obtain the following 2016-2017 estimates for Ke according to this approach:

Minimum: Ke = 4.03 + 2 = 6.03%

Maximum: Ke = 4.03 + 3 = 7.03%

Best Estimate: Ke = 4.03 + 2.5 = 6.53%

If we add 50 basis points for flotation costs, we end up with Ke estimates in the 6.53-7.53% range, with a **best estimate of 7.03%**.

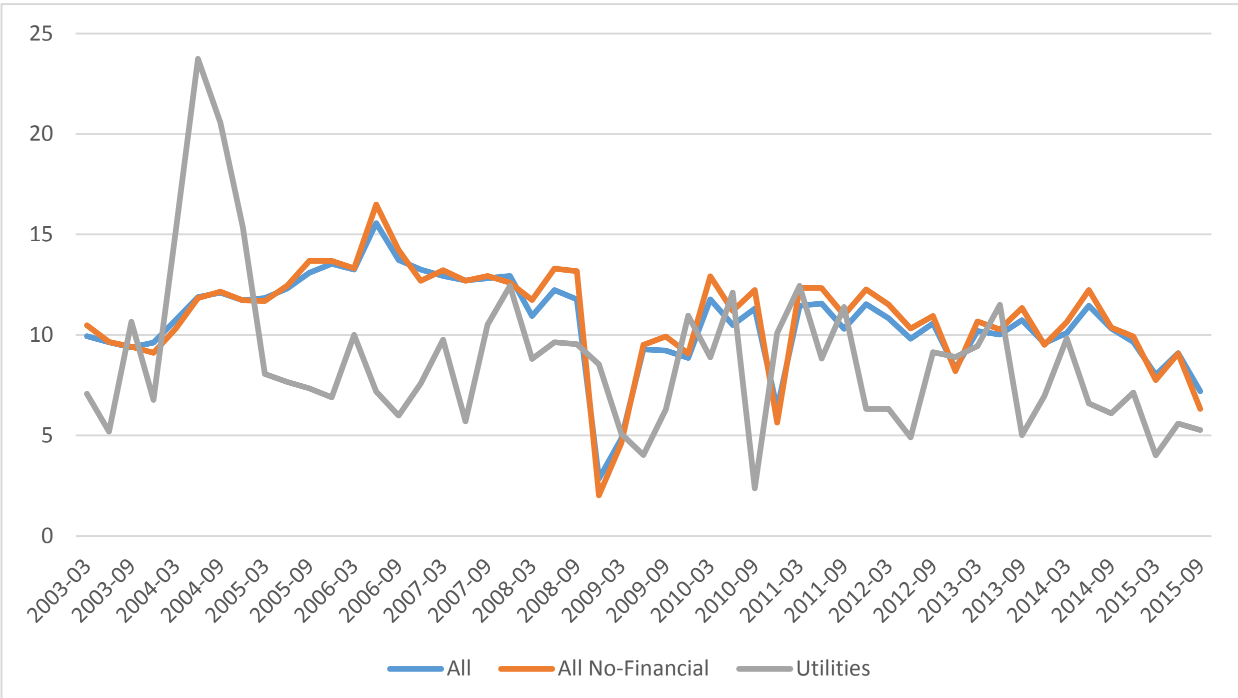
This 7 percent estimate falls half way between the CAPM estimate of 6% and the DCF estimate of 8.0%.

3.4 ROEs and Price-to-Book (P/B) Ratios

Figure 16 depicts annualized quarterly ROE data for Canadian firms and Canadian utilities from 2003 to Q3, 2015. Over this period, the average ROE for all companies was 10.7%, 10.9% for all non-financial companies, and 8.7% for utilities. We can see that it was generally a good period for all types of companies in terms of ROEs, which fell between 2.9 and 15.6% for all companies, 2.0 and 16.5% for all non-financials, and 2.4 and 23.7% for utilities.

FIGURE 16

CANADIAN ROEs– 2003-Q3, 2015



Data Source: CANSIM.

Table 14 provides similar positive results for Alberta utilities over the 2009 to 2014 period according to their Rule 005 reports with annual averages ranging from 8.8% to 9.9%, and always above the allowed ROE. The six-year overall average was 9.4%, well above the average allowed ROE over the period of 8.68%. So overall, we can say that these utilities generate ROEs that are generally above the allowed rates of 9% (2009-10), 8.75% (2011-12), and 8.3% (2013-14), with Alberta ROEs averaging 9.6% during 2013-14, 1.3% above the allowed ROE. With average ROEs of 9.4%, the results are consistent with the overall stats provided in Figure 16 for Canadian utilities, and with those provided earlier in Table 10 of the DCF analysis.

TABLE 14

REPORTED ROEs – ALBERTA UTILITIES 2009-2014

Reported ROEs	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**	**Average**	**Median**
Fortis Alberta	9.77%	9.49%	9.99%	9.73%	9.63%	9.13%	9.62%	9.68%
ATCO Elec Dist	9.74%	10.99%	12.14%	11.50%	12.57%	12.62%	11.59%	11.82%
ATCO Gas	10.95%	11.86%	11.01%	10.98%	9.67%	11.57%	11.01%	10.99%
AltaLink	8.44%	9.35%	9.28%	9.48%	9.10%	9.30%	9.16%	9.29%
ATCO Pipelines	10.31%	10.16%	11.16%	11.53%	10.85%	10.88%	10.82%	10.87%
ATCO Elec Trans	8.91%	9.84%	10.66%	9.87%	10.21%	9.63%	9.85%	9.86%
AltaGas	11.27%	12.50%	10.17%	6.19%	4.86%	8.94%	8.99%	9.56%
ENMAX Dist	7.82%	8.05%	10.22%	6.71%	6.79%	10.39%	8.33%	7.94%
ENMAX Trans	7.09%	5.90%	0.49%	4.08%	6.61%	12.84%	6.17%	6.26%
EPCOR Dist	10.31%	9.74%	8.10%	8.03%	10.76%	4.48%	8.57%	8.92%
EPCOR Trans	11.59%	7.17%	10.82%	8.36%	9.71%	9.20%	9.48%	9.46%
Average	9.65%	9.55%	9.46%	8.77%	9.16%	9.91%	9.42%	9.51%
Median	9.77%	9.74%	10.22%	9.48%	9.67%	9.63%	9.48%	9.56%
Allowed ROEs	8.30%	8.30%	8.75%	8.75%	9.00%	9.00%	8.68%	8.75%

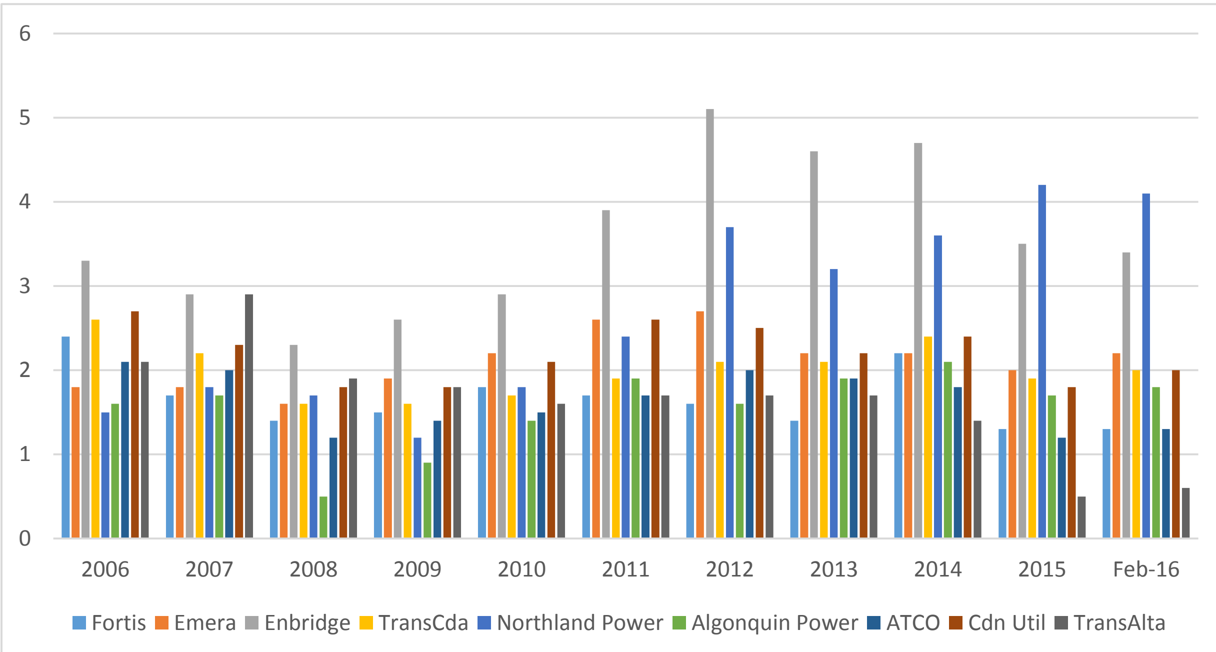
Data Source: Rule 005 reports.

ROE data suggest that utilities have earned almost as much as the average Canadian company, yet we know that they are less risky than average. In fact, ROE numbers are above the required return estimates determined using CAPM, DCF and BYPRP approaches, with best estimates of 6.0%, 8.0% and 7.0% and which ranged from 4.2% to 9.0%. All of this suggests that they would make attractive investments. Certainly from an investor's point of view, low-risk utilities that have regulated returns that exceed "required" rates of return based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 6.0% figure that was determined above. If the utility earned the prescribed ROE of 8.3%, then that investor would surely be pleased. Of course, this does not mean that the actual return on the stock was 8.3%; however there is an obvious relationship between the two. I will examine this relationship by reference to price-to-book (P/B) ratios and stock returns.

I begin by considering the P/B ratios for the utilities discussed previously in the DCF analysis. The individual P/B ratios for the firms are presented in Figure 17. It is obvious that almost all of the ratios are above 1 throughout the entire period, with the exception of the P/B ratio for Transalta in 2015 and February 2016, and Algonquin in 2008 and 2009. In addition we can observe that they have generally risen over the period, and are now all at or above 2, with the exception of Transalta (0.6) and Fortis (1.3). The summary statistics provided in Table 15 show that the average P/B ratio has exceeded 2 since 2011, and is presently in the 2.1 to 2.2 range, depending on which sub-set of firms is considered.

FIGURE 17

UTILITY P/B RATIOS – 2006-Feb 2016



Data Source: Morningstar at www.morningstar.ca.

TABLE 15

P/B RATIO SUMMARY STATISTICS (2006-Feb 2016)

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Feb-16**
Average	2.23	2.14	1.56	1.63	1.89	2.27	2.56	2.36	2.53	2.01	2.08
Median	2.10	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.00
Max	3.30	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	4.20	4.10
Min	1.50	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.40	0.50	0.60
Average excl TransAlta and Northland	2.36	2.09	1.49	1.67	1.94	2.33	2.51	2.33	2.54	1.91	2.00
Median	2.40	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.00
Max	3.30	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	3.40
Min	1.60	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.80	1.20	1.30
Average (Fortis, Emera, Enbridge, TransCda)	2.53	2.15	1.73	1.90	2.15	2.53	2.88	2.58	2.88	2.18	2.23
Median	2.50	2.00	1.60	1.75	2.00	2.25	2.40	2.15	2.30	1.95	2.10
Max	3.30	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	3.40
Min	1.80	1.70	1.40	1.50	1.70	1.70	1.60	1.40	2.20	1.30	1.30

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least "fair," if not above fair. This is consistent with the Commission's statement in the 2011 Decision. The Commission confirmed the usefulness of P/B ratios in its 2013 decision (page 48, paragraph 221) noting:

> "Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity."

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[21] P/B = (ROE – g) / (Ke – g)

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke. This is consistent with the discussion above. If we "plugged" the average 2006-2015 utility index ROE of 8.7% into the equation, as well as current average P/B ratios of 2.1, 2.3, and 2.5, and then used a 3% long-term growth rate, we would get implied Ke figures of 5.7%, 5.5% and 5.3% respectively. These estimates are consistent with my CAPM estimate of 5.5% provided above if we subtract the 50 basis points that was added for financial flexibility. While I will not assign any weight to this estimate for purposes of determining Ke, the bottom line of this discussion is that the P/B ratios for utilities reported above indicate that Canadian utilities appear to be earning a satisfactory (or more than satisfactory) ROE, and have done so for quite some time.

3.5 Summary of ROE Calculations

Normally, I would choose to rely more heavily on my CAPM estimates over DCF estimates in determining the appropriate ROE. CAPM is much more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to DCF approaches, they were used by[22]:

[21] This is true if we use the following sustainable growth rate for "g" in the DDM: g = (1 – payout) × ROE.
[22] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."

- only 15% of U.S. CFOs - versus over 70% for CAPM (Graham and Harvey, 2001)
- about 12% of Canadian CFOs - versus close to 40% for CAPM (Baker et al, 2011)

These advantages also make CAPM more intuitive from the point of view of a utility hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries discussed earlier. However, I have chosen to give all three model estimates equal weighting, based on the fact that the CAPM estimates are lower than typical due to low RFs. I also gave equal weighting to the BYPRP approach which is more widely used than DCF approaches due to its intuitive nature, and because it adjusts for both borrowing rates and risk. Thus the BYPRP approach accounts for interactions between debt and equity markets.

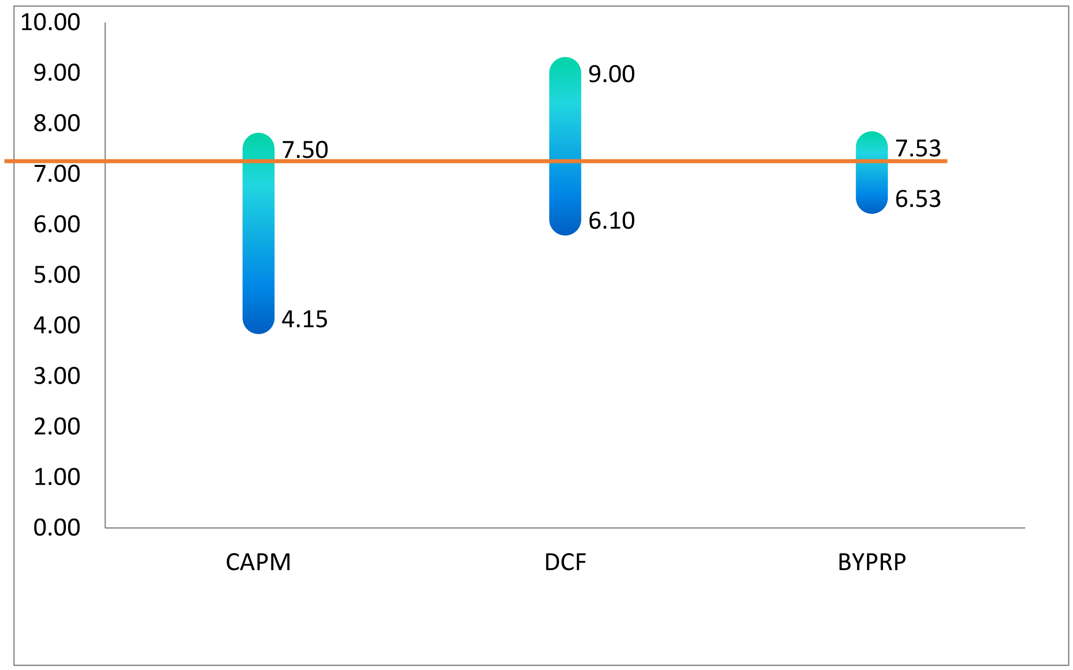
Based on an equal weighting of the three approaches, I determine the following best estimate for Alberta utility ROEs:

$$Ke = (1/3)(6.0) + (1/3)(8.0) + (1/3)(7.0) = 7.0\%$$

This estimate lies centrally in the estimate ranges for the three models, as depicted in Figure 18 below.

FIGURE 18

ROE ESTIMATE RANGES



This estimate is very reasonable when compared to expected long-term overall stock market returns in the 7-9%, when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 7-9% range are consistent with experienced long-term real stock returns of 6-7%. The ROE estimate is also consistent with our current low interest rate environment, which can be expected to change only gradually over the next few years.

4. CAPITAL STRUCTURE ISSUES

4.1 Background

4.1.1 Alberta Utilities' Operating Environment

The utilities provided a total of 19 rating reports for the Alberta utilities, with 15 of them being from calendar year 2015. All 15 of the 2015 reports refer to low business risk as the #1 strength (in the case of DBRS reports) or rate the utilities as Excellent in terms of Business Risk (in the case of S&P reports).23 This is true for operating companies such as Fortis Alberta Inc. and is also true for holding companies such as CU Ltd., which arguably faces more business risk than a pure play regulated operating utility. Strong regulatory support is generally cited as a contributing factor to this low business risk assessment. I concur with these assessments.

The utilities' evidence provides numerous quotes from debt rating reports suggesting that rating agencies consider the UAD Decision is a big risk facing Alberta utilities. However, as noted above, Alberta utilities continue to be rated excellent with respect to business risk by S&P, while low business risk is the #1 strength in DBRS reports. For example, the August 12, 2015 debt rating report for CU Inc. rates CU Inc. as "Good" in terms of "Stranded Asset Cost Recovery" and merely notes that "there have been minimal examples of stranded costs in the Alberta electricity market." This type of message seems to be a common theme in terms of the discussion of the UAD Decision in debt rating reports – i.e., there have been no material issues arising from it, and Alberta utilities continue to have low business risk.

Further, as noted by Mr. Stauft in his evidence, the costs to date have been trivial relative to their rate base, and the likelihood of future stranded costs is minimal since the Alberta utility industry has already undergone the major restructuring, which tends to be associated with such costs. However, the utilities are asking for an additional 1% increase in ROE or more to compensate them for such "potential" losses, which is the equivalent of compensating them for recurring annual losses of over $75 million per year, according to Mr. Stauft's analysis – or about 5% of

[23] Technically, the Fortis Inc. January 5, 2015 report states that its # 1 strength is "strong and stable dividends from low-risk utilities, which is essentially the same as saying low business risk.

the 2014 aggregate rate base of $21.2 billion.[24] In addition, in their discussion of the UAD, the utilities do not account for the fact that the UAD Decision also holds the possibility that "gains" will accrue to shareholders, as noted in the AUC's 2013 Decision (pages 71-72, paragraphs 350 and 351), where the Commission concluded:

> "Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores Block* decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.
>
> In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision."

In fact, Mr. Stauft's evidence suggests that gains have likely exceeded losses to date.

4.1.2 Economic Conditions and Alberta Utilities

Section 2 shows that global economic conditions have stabilized, as have Canadian capital market conditions. While real GDP growth for Alberta is predicted to be below average in 2016, it is expected to experience positive growth (1.6%), before growth increase above 2% in subsequent years. Relatedly, oil prices are expected to continue their rise which has begun over the last few weeks. So overall, we can say that the Canadian and Alberta economies are entering a recovery period that will be followed by more normal growth in the intermediate term. In any event, economic and capital market conditions are far from those existing at the peak of the 2008-2009 financial crisis. However, regulated utilities are not as greatly influenced by economic cyclicality to the extent of traditional businesses. This is true of Alberta utilities. For example, in 2009 real GDP growth in Alberta was -4.1%, yet the average EBIT/Sales ratio for Alberta utilities was 29.1%, above the 2005-2014 average of 28.3% as reported in Table 19,

[24] This is calculated as 1% times the 2014 aggregate equity base figure across the utilities of $7.569 billion, which generates $75.7 million in additional net income available to common equity holders after taxes due to a 1% increase in ROE.

while the average of the individual utility EBIT growth rates was 17.3%, versus the 2005-2014 average of 10.3%. During 2009, the average ROE earned by Alberta utilities was 9.91% as reported in Table 17, which was 91 basis points above the allowed ROE of 9.0%. This indicates that the earnings of Alberta utilities are resilient in the face of economic decline, which shows they have low business risk. I provide compelling evidence to support this conclusion in Sections 4.2 and 4.3.

4.2 A Quantitative Review of Alberta Utilities' Performance

This section provides a brief review of the performance of the Alberta utilities using information provided for the 2005-2014 period in their Rule 005 reports. Table 16 summarizes the growth in the aggregate figures for the Alberta utilities, excluding EPCOR, over the 2005-2014 period.25 Table 16 shows that aggregate revenue rose more than two-fold over this period from $1.43 billion to $3.36 billion, representing a compound growth rate of 10% per year. By comparison, real GDP growth in Alberta demonstrated compound annual growth of 3.2%. Over the same period, EBIT (a commonly used measure of operating income) rose almost threefold, representing an annual compound growth rate of 12.4%. The fact that EBIT grew faster than revenue, indicates that regulatory support, including the numerous cost pass-through mechanisms in place, are working effectively and enabling firms to continue to earn solid profit margins on their revenues. This is further attested to by the fact that the EBIT/sales ratio was above 30% in 2005 (31.9%) and was even higher in 2014 (38.7%). Finally, we get a similar if not stronger message if we look at the figures for net income available to common equity, which grew over threefold at an annual compound growth rate of 15.7%. Not surprisingly, the net income margins also increased from 12.4% to 19.4% - very healthy margins indeed. Overall, these figures show that 2005-2014 was a very good decade for Alberta utilities.

[25] Table 16 includes reported figures for Alberta utilities excluding EPCOR Distribution and Transmission (due to missing data in their 2005 Rule 005 reports).

TABLE 16

ALBERTA UTILITIES GROWTH STATISTICS (2005-2014)

	Revenue	EBIT	Net Income Available to CE	EBIT/Sales	NIACE/Sales
2005	1426.034	454.673	176.292	31.88%	12.36%
2014	3358.946	1299.059	652.403	38.67%	19.42%
Geometric Mean Growth	9.99%	12.37%	15.65%		
Alberta Real GDP Growth 2005-2014[26]	3.17%				

An even more compelling way of reviewing the performance of Alberta utilities is to examine their ability to earn their allowed ROEs on a consistent basis. Table 17 provides such a comparison of the reported ROEs by Alberta utilities in their Rule 005 reports with the allowed ROEs. The yearly average and median figures show that Alberta utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average reported ROE was 0.18% below the allowed ROE, while the median equalled it. We get a similar message if we look at the weighted average ROE (Wt Av ROE). This is estimated by weighting each utility according to its average revenue over the period, relative to total revenue over the period, which effectively gives larger weight to the larger utilities.

TABLE 17

ALBERTA UTILITIES REPORTED ROEs (2005-2014)

2014	2013	2012	2011	2010	2009	2008	2007	2006	2005

[26] Alberta real GDP growth figures for 2005-2013 were obtained from the Conference Board of Canada at: http://www.conferenceboard.ca/hcp/provincial/economy/gdp-growth.aspx (March 14, 2016). The 2014 GDP growth figure was obtained at the Alberta Treasury Board and Finance website at: http://www.finance.alberta.ca/aboutalberta/osi/index.html#gdp (March 14, 2016).

Fortis Alberta	9.77%	9.49%	9.99%	9.73%	9.63%	9.13%	9.19%	8.79%	10.28%	10.45%
ATCO Elec Dist	9.74%	10.99%	12.14%	11.50%	12.57%	12.62%	10.27%	10.26%	9.38%	9.10%
ATCO Gas	10.95%	11.86%	11.01%	10.98%	9.67%	11.57%	11.67%	10.83%	8.26%	5.81%
AltaLink	8.44%	9.35%	9.28%	9.48%	9.10%	9.30%	8.50%	9.20%	9.40%	10.60%
ATCO Pipelines	10.31%	10.16%	11.16%	11.53%	10.85%	10.88%	9.51%	8.21%	10.61%	10.19%
ATCO Elec Trans	8.91%	9.84%	10.66%	9.87%	10.21%	9.63%	8.74%	8.50%	9.28%	9.61%
AltaGas	11.27%	12.50%	10.17%	6.19%	4.86%	8.94%	8.75%	8.51%	8.93%	9.50%
ENMAX Dist	7.82%	8.05%	10.22%	6.71%	6.79%	10.39%	8.27%	5.08%	6.99%	9.50%
ENMAX Trans	7.09%	5.90%	0.49%	4.08%	6.61%	12.84%	9.34%	6.58%	10.85%	
EPCOR Dist	10.31%	9.74%	8.10%	8.03%	10.76%	4.48%	7.81%	9.82%	8.85%	9.16%
EPCOR Trans	11.59%	7.17%	10.82%	8.36%	9.71%	9.20%	11.12%	10.47%		
Average	**9.65%**	**9.55%**	**9.46%**	**8.77%**	**9.16%**	**9.91%**	**9.38%**	**8.75%**	**9.28%**	**9.32%**
Median	**9.77%**	**9.74%**	**10.22%**	**9.48%**	**9.67%**	**9.63%**	**9.19%**	**8.79%**	**9.33%**	**9.50%**
Max	11.59%	12.50%	12.14%	11.53%	12.57%	12.84%	11.67%	10.83%	10.85%	10.60%
Min	7.09%	5.90%	0.49%	4.08%	4.86%	4.48%	7.81%	5.08%	6.99%	5.81%
StDev	1.45%	1.95%	3.15%	2.37%	2.23%	2.28%	1.20%	1.72%	1.15%	1.42%
Wt Av ROE	**9.73%**	**10.17%**	**10.32%**	**9.69%**	**9.86%**	**10.03%**	**9.52%**	**9.18%**	**8.92%**	**8.70%**
Allowed ROEs	8.30%	8.30%	8.75%	8.75%	9.00%	9.00%	8.75%	8.51%	8.93%	9.50%
Diff Avg	**1.35%**	**1.25%**	**0.71%**	**0.02%**	**0.16%**	**0.91%**	**0.63%**	**0.24%**	**0.35%**	**-0.18%**
Diff Median	**1.47%**	**1.44%**	**1.47%**	**0.73%**	**0.67%**	**0.63%**	**0.44%**	**0.28%**	**0.40%**	**0.00%**
Diff Wt Avg	**1.43%**	**1.87%**	**1.57%**	**0.94%**	**0.86%**	**1.03%**	**0.77%**	**0.67%**	**-0.01%**	**-0.80%**

Table 18 provides the summary statistics for each utility over the period, and aggregates them. These statistics show that ROEs averaged 9.31% across all utilities and all years, while allowed ROEs averaged 8.78%. The last three rows in this table show that the annual averages of reported ROEs exceeded the allowed ROEs over the 10-year period by 0.54%, with the annual median ROEs exceeding allowed ROEs by a 10-year average of 0.75%. The weighted average ROE exceeds the allowed average by an even higher margin of 0.83%, indicating that the larger utilities have been better than average at earning above the allowed ROE. This lends strong support to the evidence provided in Table 16, showing that Alberta utilities operate in a low risk environment that enables them to earn attractive returns – i.e., since they are consistently able to earn their allowed ROEs or higher. This is a strong indication that the utilities possess low risk overall.

TABLE 18

SUMMARY STATISTICS – ALBERTA REPORTED ROEs (2005-2014)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)[27]**
Fortis Alberta	9.65%	9.68%	10.45%	8.79%	0.52%	0.054
ATCO Elec Dist	10.86%	10.63%	12.62%	9.10%	1.31%	0.120
ATCO Gas	10.26%	10.96%	11.86%	5.81%	1.89%	0.185
AltaLink	9.27%	9.29%	10.60%	8.44%	0.59%	0.064
ATCO Pipelines	10.34%	10.46%	11.53%	8.21%	0.94%	0.091
ATCO Elec Trans	9.53%	9.62%	10.66%	8.50%	0.67%	0.071
AltaGas	8.96%	8.94%	12.50%	4.86%	2.22%	0.248
ENMAX Dist	7.98%	7.94%	10.39%	5.08%	1.69%	0.212
ENMAX Trans	7.09%	6.61%	12.84%	0.49%	3.65%	0.516
EPCOR Dist	8.71%	9.01%	10.76%	4.48%	1.79%	0.206
EPCOR Trans	9.81%	10.09%	11.59%	7.17%	1.50%	0.153
Average	**9.31%**	**9.38%**	11.44%	6.45%	1.53%	**0.174**
Median	**9.53%**	**9.62%**	11.53%	7.17%	1.50%	**0.153**
Max	10.86%	10.96%	12.84%	9.10%	3.65%	0.516
Min	7.09%	6.61%	10.39%	0.49%	0.52%	0.054
StDev	1.09%	1.26%	0.92%	2.62%	0.91%	

	Average	Median	Max	Min	StDev
Allowed ROEs	8.78%	8.75%	9.50%	8.30%	0.36%
Diff Avg	**0.54%**	0.49%	1.35%	-0.18%	0.52%
Diff Median	**0.75%**	0.65%	1.47%	0.00%	0.53%
Diff Wt Avg	**0.83%**	0.90%	1.87%	-0.80%	0.78%

[27] This column reports the coefficient of variation of ROE for ease of reporting purposes. It will be defined and discussed later in the analysis.

4.3 A Quantitative Assessment of Alberta Utilities' Risk

4.3.1 Business Risk

My examination of the Alberta utilities' operating and regulatory environment above suggests they possess low business risk. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great an ability to pass through increases in their costs to their customers. As noted in Section 4.1, debt rating reports consistently suggest that the Alberta utilities NP and most other regulated Canadian utilities have low business risk.

Most experts assessing "business risk" would agree that it refers to some variation of factors that cause uncertainty, or volatility, in operating income. For example, the 2013 CFA curriculum (Reading 38, page 82) states: "**Business risk** is the risk associated with operating earnings. Operating earnings are risky because total revenues are risky, as are the costs of producing revenues." This definition is consistent with the definition of business risk proposed by Dr. Roger Morin in the 2003 Newfoundland rate hearings, as noted on page 31 of the Newfoundland Public Utilities Board (PUB) Order No. P.U. 19 (2003), as quoted below:

> Dr. Morin's definition of Business Risk:
>
> "Refers to the relative **variability of operating profits** induced by the external forces of demand for and supply of the firm's products, by the presence of fixed costs, by the extent of diversification or lack thereof of services, and by the character of regulation."

This definition was accepted by the PUB at that time as noted on page 31 of Order No. P.U. 19 (2003):

> "The Board feels the above definitions are consistent and reasonable. The Board accepts these definitions and sees no particular conflict in terms of the evidence presented during the hearing."

Similarly, in response to AML/EDTI-UCA-2016FEB-011, Mr. Hevert confirmed that he was referring to "operating earnings" in the following passage from his evidence (X0082, page 16, lines 13-17) discussing business risk:

> **"**Business risk reflects the uncertainty associated with owning the subject company's common stock, without the use of debt and/or preferred capital. Examples of the business risks generally faced by utilities include, but are not limited to, the regulatory environment, customer mix and concentration, service territory economic growth, capital intensity and size, and the degree of operating leverage, all of which have a direct bearing on earnings."

In this section, I use a variation of a commonly used measure of operating income volatility, the coefficient of variation of the EBIT/Sales ratio (hereafter CV(EBIT/Sales), to *quantify* a firm's level of business risk.[28] The CV is determined by dividing the standard deviation (SD) of the EBIT/Sales ratio by the average EBIT/Sales level. The rationale for using the CV as a measure of EBIT/Sales volatility rather than simply using the SD of EBIT/Sales, is that the SD is affected by the size of the average EBIT/Sales ratio. In other words, firms with larger EBIT/Sales ratios would have higher SDs of EBIT/Sales, even if they have less volatility, simply because the level of the EBIT/sales figures used to determine the SD are higher. This is indeed the case in my analysis – for example, the average EBIT/Sales ratio across the Alberta utilities over this period is 28.3%, much higher than the U.S. utility sample average of only 16.1%.[29] The CV is more appropriate in such instances and is commonly used to measure volatility since it effectively "scales" the SD of EBIT/Sales when it is divided by the average level of EBIT/Sales.

This measure (i.e., CV(EBIT/Sales) is calculated as the standard deviation of the EBIT/Sales ratio (2005-2014) divided by the average of the EBIT/Sales ratio over this period. Using the EBIT/Sales ratio rather than the level of EBIT is a valid measure of business risk, since it measures volatility in the operating profit margins for firms. It also has the advantage that, as a

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[28] For example, the 2013 CFA curriculum (Reading 28, page 351) refers to the use of CV(EBIT) as a measure of business risk, as do numerous finance and accounting texts such as Financial Management: Principles and Applications, 6th edition, by J. William Petty, Sheridan Titman, Arthur J. Keown, Peter Martin, John D. Martin, Michael Burrow, Hoa Nguyen, 2011, Pearson Higher Education.

[29] The fact that the U.S. utilities have a much lower average EBIT/Sales ratio in and of itself also indicates the U.S. utilities have higher business risk.

ratio, the expected value and past average values will often coincide since these profitability margins often tend to gravitate to some long-term average.

4.3.2 Alberta Utilities

Table 19 provides the CV(EBIT/Sales) ratios for the Alberta utilities over the 2005-2014 period. The average CV across all utilities is 0.158, while the median is 0.132 and the weighted average is 0.137. Most of the individual utility CV estimates fall between 0.10 and 0.16, with the exceptions of ATCO pipelines, which has a CV of 0.060, and AltaGas and ENMAX Transmission, which have CVs of 0.394 and 0.241 respectively. Since these three utilities have relatively low weighting according to average revenue, the median and weighted average CV estimates are lower at just over 0.13. Table 19 also provides summary statistics for EBIT/Sales and EBIT growth for the Alberta utilities, which confirm the two points made earlier with respect to the discussion of the results reported in Table 16. Namely, the Alberta utilities have very healthy operating profit margins as measured by EBIT/Sales with average, median and weighted average figures of 28.3%, 25.4% and 28.1% respectively. They have also displayed substantial growth in EBIT over this decade with utility median growth rates across all utilities producing average, median and weighted averages of 10.3%, 9.8% and 12.1% respectively.

TABLE 19

CV(EBIT/SALES) ESTIMATES – ALBERTA UTILITIES (2005-2014)

	CV (EBIT/Sales)	EBIT/Sales	EBIT Growth(median)
Fortis Alberta	0.132	0.330	0.120
ATCO Elec Dist	0.139	0.185	0.067
ATCO Gas	0.102	0.254	0.098
AltaLink	0.127	0.437	0.156
ATCO Pipelines	0.060	0.388	0.038
ATCO Elec Trans	0.157	0.459	0.267
AltaGas	0.394	0.093	0.144

ENMAX Dist	0.154	0.191	0.041
ENMAX Trans	0.241	0.254	0.001
EPCOR Dist	0.112	0.137	0.091
EPCOR Trans	0.122	0.385	0.108
Alberta Utilities	**CV (EBIT/Sales)**	**EBIT/Sales**	**EBIT Growth(median)**
Average	**0.158**	**0.283**	**0.103**
Median	**0.132**	**0.254**	**0.098**
Max	0.394	0.459	0.267
Min	0.060	0.093	0.001
StdDev	0.090	0.125	0.072
Weighted Average	**0.137**	**0.281**	**0.121**

4.3.3 Comparing the Risk of Alberta Utilities to U.S. Utilities

The purpose of the analysis in this section is to provide quantitative evidence comparing the business risk of U.S. utilities used in the utilities' evidence to that of the Alberta utilities. In particular, the evidence provided by the utilities relies heavily on U.S. samples based on the premise that such samples are of comparable risk to Alberta utilities, and therefore require no adjustments for comparison purposes. Therefore, in order to avoid debate over my U.S. sample selection, I have used the same utilities for comparison purposes as those used by Dr. Villadsen and Mr. Hevert respectively. I was able to find the required data for 37 of the 38 total firms used by either Dr. Villadsen and/or Mr. Hevert.[30]

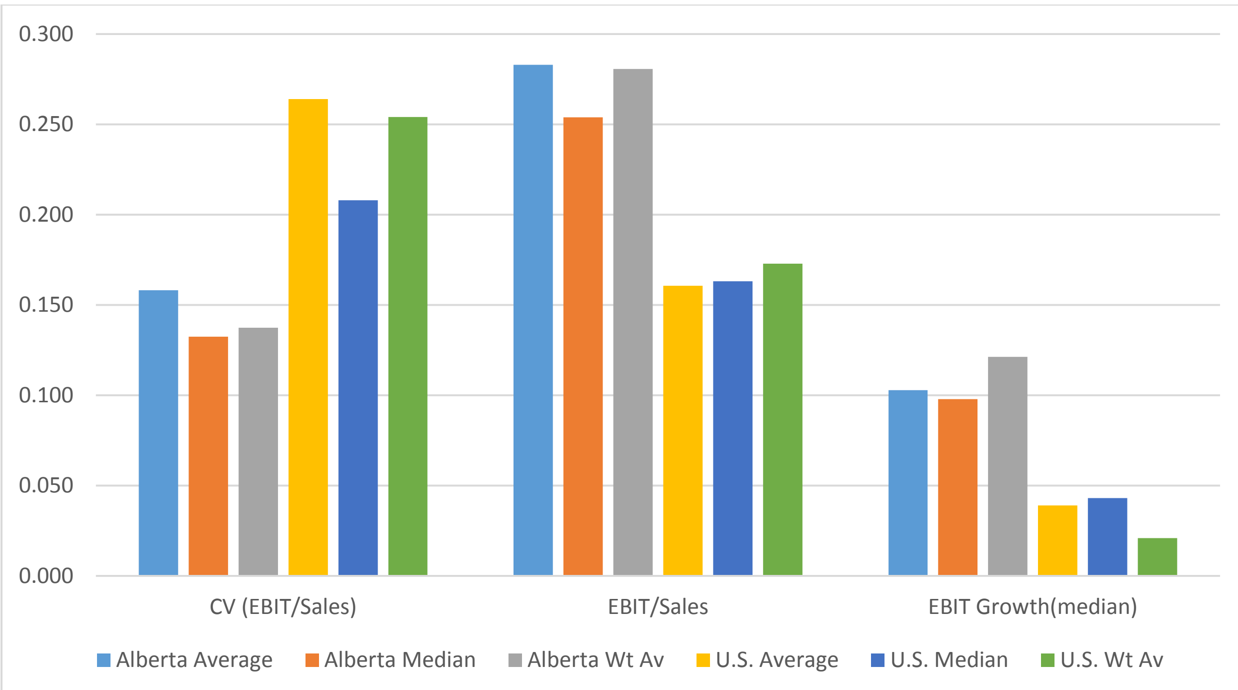
Figure 19 depicts a summary of the main results of this analysis. The evidence clearly shows that U.S. utilities have much higher volatility in their EBIT/Sales ratios as measured by the CV(EBIT/Sales). The U.S. average, median and weighted average values for the CV(EBIT/Sales) are 0.26, 0.21 and 0.25 respectively, versus corresponding figures of 0.16, 0.13 and 0.14 for Alberta utilities. These figures show that the U.S. utilities in this sample display

[30] There was some overlap in the chosen utilities, with 18 of the utilities being included in both of their U.S. proxy groups.

greater volatility in operating profit margins, as measured by EBIT/Sales. In addition, Figure 19 shows clearly that the Alberta utilities have much higher operating profit margins with average, median and weighted average EBIT/Sales ratios of 0.28, 0.25 and 0.28 versus corresponding U.S. figures of 0.16, 0.16 and 0.17. Finally, the last bar chart in Figure 19 shows that the median annual percentage EBIT growth was also much higher for the Alberta utilities with average, median and weighted average figures of 10%, 9.8% and 12.1% versus corresponding U.S. figures of 3.9%, 4.3% and 2.1%. So overall, Figure 19 shows that Alberta utilities have less volatility in operating profit margins, which demonstrates lower business risk, while at the same time maintaining higher profit margins and higher growth in EBIT levels. This evidence shows clearly that the Alberta utilities have lower business risk than their U.S. counterparts in this sample.

FIGURE 19

ALBERTA VERSUS U.S. UTILITIES (2005-2014)



Data Source: Alberta data are obtained from the Rule 005 reports; U.S. data are obtained from the Compustat database.

Table 20 provides the individual results for the U.S. utilities, confirming that the patterns displayed in Figure 19 are not driven by the use of averages or medians. In particular, I would note that only 4 of the 37 CV estimates for the U.S. utilities is below the median Alberta CV estimate of 0.132, with the remaining 33 CV estimates being above this level, some being much higher. None of the individual U.S. utility EBIT/Sales average ratios is higher than the Alberta median figure of 25.4%, nor are any of the 37 median EBIT growth figures higher than the median growth figure of 9.8% for the Alberta utilities. So, the conclusions that the U.S. utilities display greater operating income volatility despite lower margins and growth in EBIT, stands firmly.

1 **TABLE 20**

2 **CV(EBIT/SALES) ESTIMATES – U.S. UTILITIES (2005-2014)**

	CV (EBIT/Sales)	**EBIT/Sales**	**EBIT Growth (median)**
ALLETE INC	0.232	0.173	0.045
ALLIANT ENERGY CORP	0.340	0.163	0.037
AMEREN CORP	0.786	0.149	0.038
AMERICAN ELECTRIC POWER CO	0.072	0.202	0.065
ATMOS ENERGY CORP	0.288	0.094	0.061
AVISTA CORP	0.158	0.137	0.053
CENTERPOINT ENERGY INC	0.204	0.147	0.071
CMS ENERGY CORP	0.680	0.108	-0.010
CONSOLIDATED EDISON INC	0.126	0.160	0.043
DOMINION RESOURCES INC	0.358	0.239	-0.163
DTE ENERGY CO	0.208	0.151	-0.022
EDISON INTERNATIONAL	0.297	0.173	0.041
EL PASO ELECTRIC CO	0.201	0.188	0.104
ENTERGY CORP	0.153	0.190	0.053
FIRSTENERGY CORP	0.306	0.169	-0.032
GREAT PLAINS ENERGY INC	0.314	0.184	0.098
IDACORP INC	0.166	0.213	0.136
MGE ENERGY INC	0.197	0.191	0.077
NEW JERSEY RESOURCES CORP	0.267	0.051	0.061
NEXTERA ENERGY INC	0.236	0.206	0.043
NORTHWEST NATURAL GAS CO	0.147	0.169	0.002

NORTHWESTERN CORP	0.134	0.142	0.053
OGE ENERGY CORP	0.416	0.164	0.066
OTTER TAIL CORP	0.368	0.079	0.042
PG&E CORP	0.159	0.159	0.017
PINNACLE WEST CAPITAL CORP	0.252	0.205	0.002
PNM RESOURCES INC	0.899	0.129	-0.008
PORTLAND GENERAL ELECTRIC CO	0.174	0.151	0.085
PUBLIC SERVICE ENTRP GRP INC	0.165	0.229	-0.024
SCANA CORP	0.249	0.174	0.073
SEMPRA ENERGY	0.209	0.183	0.037
SOUTH JERSEY INDUSTRIES INC	0.154	0.146	0.057
SOUTHWEST GAS CORP	0.169	0.120	0.039
VECTREN CORP	0.097	0.134	0.009
WESTAR ENERGY INC	0.143	0.222	0.081
WGL HOLDINGS INC	0.262	0.092	0.042
XCEL ENERGY INC	0.169	0.159	0.076
U.S. Group	**CV (EBIT/Sales)**	**EBIT/Sales**	**EBIT Growth**
Average	**0.264**	**0.161**	**0.039**
Median	**0.208**	**0.163**	**0.043**
Max	0.899	0.239	0.136
Min	0.072	0.051	-0.163
StdDev	0.178	0.042	0.050
Wt. Average	**0.254**	**0.173**	**0.021**

Finally, while this sample of U.S. utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Alberta counterparts. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts – although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions.

Another way of comparing the riskiness of Alberta utilities to that of the U.S. utility proxy groups is to compare volatility in earned ROEs; although this is more of a measure of total risk (i.e., business and financial risk) rather than business risk, since financial leverage influences net income, whereas EBIT is not influenced directly by financial leverage.[31] Table 21 provides the summary statistics for earned ROEs for the U.S. sample, identical to those provided for the Alberta utilities in Table 18. Table 21 shows that the reported ROEs are higher for the U.S. utilities on average, with an average across all 37 utility averages of 10.75%, versus the corresponding figure of 9.31% across the Alberta utilities. This is expected, since allowed ROEs in the U.S. have been higher than in Canada over the last decade. However, if we look at the last column in Table 21 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the U.S. firms to the results in the last column of Table 18 for Alberta utilities, we can see that the U.S. utilities displayed much greater volatility in ROEs than the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the U.S. utilities were 0.36 and 0.23 respectively, versus corresponding figures of 0.17 and 0.15 for Alberta utilities as reported in Table 18.

[31] Unfortunately, it is not practical to compare the earned ROEs to allowed ROEs for the U.S. utilities as I did for the Alberta utilities in Table 17. This is because the U.S. utilities included in the U.S. proxy groups are primarily holding companies that own several distinct operating utilities, which operate in numerous jurisdictions.

1 **TABLE 21**

2 **SUMMARY STATISTICS – U.S. REPORTED ROEs (2005-2014)**

	Average	Median	Max	Min	StDev	CV(ROE)
ALLETE INC	9.11%	9.14%	13.16%	2.11%	3.10%	0.340
ALLIANT ENERGY CORP	10.42%	11.29%	16.75%	0.43%	4.62%	0.443
AMEREN CORP	5.64%	8.78%	10.67%	-12.30%	6.86%	1.215
AMERICAN ELECTRIC POWER CO	11.07%	10.61%	14.29%	8.59%	1.96%	0.177
ATMOS ENERGY CORP	10.00%	9.57%	11.98%	9.17%	0.94%	0.094
AVISTA CORP	8.44%	8.76%	14.79%	4.20%	2.78%	0.329
CENTERPOINT ENERGY INC	21.51%	20.53%	42.43%	7.23%	10.72%	0.498
CMS ENERGY CORP	7.54%	12.84%	14.86%	-9.53%	9.28%	1.231
CONSOLIDATED EDISON INC	10.19%	9.88%	13.30%	8.92%	1.38%	0.135
DOMINION RESOURCES INC	14.16%	13.10%	25.11%	2.64%	6.32%	0.446
DTE ENERGY CO	10.17%	9.50%	16.60%	7.51%	2.50%	0.246
EDISON INTERNATIONAL	11.79%	14.10%	19.19%	-0.91%	7.12%	0.604
EL PASO ELECTRIC CO	11.21%	11.80%	13.92%	6.68%	2.10%	0.188
ENTERGY CORP	13.02%	14.45%	16.09%	7.94%	3.02%	0.232
FIRSTENERGY CORP	9.62%	10.28%	14.95%	2.36%	4.57%	0.475
GREAT PLAINS ENERGY INC	8.71%	7.54%	14.22%	5.88%	2.77%	0.318
IDACORP INC	9.39%	10.20%	10.88%	6.31%	1.57%	0.167
MGE ENERGY INC	11.86%	12.02%	13.01%	9.49%	1.13%	0.095
NEW JERSEY RESOURCES CORP	13.92%	15.05%	17.92%	3.75%	4.33%	0.311
NEXTERA ENERGY INC	13.58%	13.48%	15.27%	11.74%	1.27%	0.094
NORTHWEST NATURAL GAS CO	10.18%	10.52%	12.43%	7.81%	1.67%	0.164
NORTHWESTERN CORP	9.29%	9.72%	11.71%	5.14%	2.09%	0.225
OGE ENERGY CORP	14.84%	14.24%	19.05%	13.03%	1.77%	0.119
OTTER TAIL CORP	6.43%	8.22%	14.51%	-2.09%	5.91%	0.918
PG&E CORP	10.77%	10.70%	15.64%	6.33%	3.13%	0.291
PINNACLE WEST CAPITAL CORP	8.27%	9.35%	10.56%	1.98%	2.65%	0.320
PNM RESOURCES INC	4.07%	6.56%	11.51%	-15.96%	7.96%	1.957
PORTLAND GENERAL ELECTRIC CO	7.80%	7.56%	11.85%	5.03%	2.07%	0.265
PUBLIC SERVICE ENTRP GRP INC	15.10%	14.34%	20.49%	11.53%	3.41%	0.226
SCANA CORP	11.55%	11.51%	13.34%	10.45%	0.79%	0.068
SEMPRA ENERGY	13.71%	13.82%	22.99%	8.32%	4.68%	0.341
SOUTH JERSEY INDUSTRIES INC	13.89%	13.98%	18.26%	11.08%	2.34%	0.169
SOUTHWEST GAS CORP	9.22%	9.52%	11.16%	6.20%	1.81%	0.197

VECTREN CORP	10.45%	10.15%	12.50%	8.95%	1.16%	0.111
WESTAR ENERGY INC	9.91%	9.85%	11.67%	8.01%	0.98%	0.099
WGL HOLDINGS INC	10.47%	10.94%	12.28%	6.43%	1.87%	0.179
XCEL ENERGY INC	10.32%	10.39%	10.69%	9.78%	0.36%	0.034
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**10.75%**	**11.20%**	15.41%	4.98%	**3.32%**	**0.360**
Median	**10.32%**	**10.52%**	14.22%	6.43%	**2.50%**	**0.232**
Max	21.51%	20.53%	42.43%	13.03%	10.72%	1.957
Min	4.07%	6.56%	10.56%	-15.96%	0.36%	0.034
StDev	3.10%	2.70%	5.73%	6.39%	2.51%	0.388

The ROE analysis above, similar to the analysis of CV(EBIT/Sales), suggests that the U.S. utilities possess greater risk than Alberta utilities. This is hardly surprising given that the U.S. sample is comprised of holding companies with various ownership structures and a variety of exposures to risks (including significant generation risks) to which Alberta operating utilities are not – at least not to the same extent. For example, Allette Inc. comprised only 67% of 2014 operating consolidated revenue from regulated operations, with 18% of operating revenue was from Allette Clean Energy. In fact, they ranked 17th in terms of 2014 market share of U.S. wind power capacity (865 MW). Great Plains Energy generated 6,660 MW in 2014, including 16% from nuclear sources. OGE generated 6,785 MW in 2014, with $90 million of planned 2015 capital expenditures on generation, out of total estimated expenditures of $370 million. So obviously generation is a big part of their operations, including pipeline assets. In fact, in a recent presentation for investors, OGE noted two major environmental challenges due to their distribution assets – i.e., taking measures to comply with Mercury Air Toxics Rules (MATS), and Regional Haze.[32] Pinnacle West has more than 6,100 megawatts of generating capacity. According to its 2014 annual report, $476 million out of a total of $1,091 million in planned 2015 capital expenditures was targeted for generation assets, including $78 million in nuclear assets. Westar has 7,200 MW of electric generation capacity. 2015 capital expenditures for generation amounted to $293.4 million and $15.6 million for nuclear fuel, out of a total of $703.8 billion.

[32] Source: EEI Conference Slides, November 2015 at: http://phx.corporate-ir.net/phoenix.zhtml?c=106374&p=irol-presentations , March 2, 2016.

Clearly many of the utilities in the U.S. sample are distinct from Alberta operating utilities in terms of the risk they face. Hence, it is not surprising that 19 of the 33 U.S. utilities included in Dr. Villadsen's U.S. samples are rated in the BBB category, while 15 of the 23 in Mr. Hevert's U.S. group also fall in the BBB category. As mentioned, 18 of the firms in their respective sample overlap, and the net result is that 24 of the 37 firms examined in Tables 21 and 22 above have debt ratings in the BBB category. It is hardly surprising that my results above confirm that Alberta utilities possess lower risk than the U.S. utilities as measured by lower volatility in operating income and ROE. As a result, I do not use U.S. samples in my analysis, since they are not good comparators in terms of the risks they possess.

4.3.4 Comparing the Risk of Alberta Utilities to Canadian Utility Proxy Groups

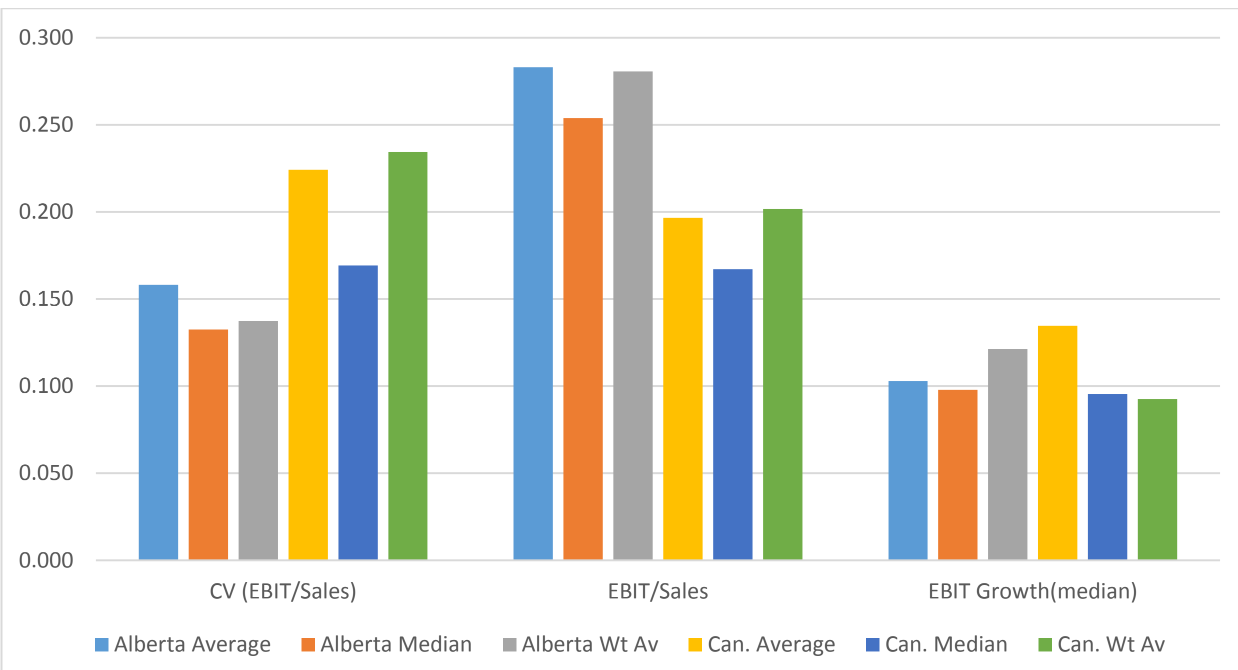
Similar to Section 4.3.3, the purpose of the analysis in this section is to provide quantitative evidence comparing the business risk of Canadian utilities to Alberta utilities. In order to avoid debate over my sample selection, I have used the same utilities for comparison purposes as those used by Dr. Villadsen and Mr. Hevert respectively. I was able to find the required data for 7 of the 8 total utilities used by either Dr. Villadsen and/or Mr. Hevert; although data limitations forced me to use the results for Gaz Metro MLP rather than those for Valener.[33]

Figure 20 depicts a summary of the main results of this analysis. The evidence shows that the Canadian utilities in this sample have higher volatility in their EBIT/Sales ratios as measured by the CV(EBIT/Sales). The Canadian average, median and weighted average values for the CV(EBIT/Sales) are 0.22, 0.17 and 0.23 respectively, versus corresponding figures of 0.16, 0.13 and 0.14 for Alberta utilities. These figures are below those for the U.S. utilities, but are greater than the Alberta figures, indicating greater volatility in operating profit margins, as measured by EBIT/Sales. Figure 20 also shows that the Alberta utilities have higher operating profit margins with average, median and weighted average EBIT/Sales ratios of 0.28, 0.25 and 0.28 versus corresponding Canadian group figures of 0.20, 0.17 and 0.20. Finally, the last bar chart in Figure

[33] There was some overlap in the chosen utilities, with 2 of the utilities being included in both of their proxy groups; although one of these utilities (CU Ltd.) is the one for which I could not obtain the required data.

20 shows that the median annual percentage EBIT growth was similar to that for the Alberta utilities which had average, median and weighted average figures of 10%, 9.8% and 12.1% versus corresponding Canadian group figures of 13.5%, 9.6% and 9.3%. So overall, Figure 20 shows that Alberta utilities have less volatility in operating profit margins, which demonstrates lower business risk, while at the same time maintaining higher profit margins and displaying similar growth in EBIT levels. This evidence shows that the Alberta utilities have lower business risk than their Canadian counterparts in this sample; but the difference is less pronounced than when they were compared to U.S. utilities. However, it is worthy of note that the Canadian utilities in the sample are all holding companies, not operating companies – hence the results are not unexpected.

FIGURE 20
ALBERTA VERSUS CANADIAN UTILITIES (2005-2014)



Data Source: The data for Enbridge Inc. and TransCanada Corp. are obtained from the Compustat database; the data for the other utilities are from their respective annual reports (2006-2014).

Table 22 provides the individual results for the Canadian utilities. There are three outliers in terms of the CV(EBIT/Sales) – Enbridge Inc. at 0.33, Algonquin at 0.54, and Gaz Metro MLP at

0.05. These results are not unexpected if we look closer at these companies. For example, Enbridge Inc. is a diversified energy services company that owns numerous businesses in Canada and the U.S. For the 12-month period ending June 30, 2015, DBRS estimated that liquid pipelines accounted for 48% of segment earnings, sponsored investments accounting for 29%, gas distribution for 13% and gas pipelines, processing and energy services for 10%.[34] Aside from being relatively small, according to the response to AML/EDTI-UCA-2016FEB18-018, Algonquin derives 39.6% of its operating earnings from unregulated assets and derives 90% of its revenue from international operations and 23% from generation. Therefore, it is not surprising that these companies display greater earnings volatility than pure operating utilities. On the other hand, while Gaz Metro is a holding company, its operating risk is considerably lower. In particular Gaz Metro is comprised of three operating companies that are primarily gas distribution companies, with distribution accounting for close to 90% of 2015 net income and gas transportation accounting for just over 8% of 2015 net income, even if close to one third of this is generated in Vermont.[35]

Turning to the EBIT/Sales average ratios, we see can that only one of the Canadian utilities (Trans Canada Corp) has an average EBIT/Sales ratio that is higher than the Alberta average figure of 28%. The EBIT/Sales ratios are generally higher than those for the U.S. utilities, which is reflected in the Canadian average of 20% versus the U.S. average of 16%. Finally, as noted above, the median EBIT growth figures are similar to those for Alberta utilities, and higher than for the U.S. utilities, with Algonquin's median EBIT growth of 40% being the sole outlier.

[34] Source: DBRS rating report for Enbridge Inc., October 2, 2015.
[35] Source: DBRS rating report for Gaz Metro Inc., December 21, 2015.

TABLE 22

CV(EBIT/SALES) ESTIMATES – CANADIAN UTILITIES (2005-2014)

	CV (EBIT/Sales)	**EBIT/Sales**	**EBIT Growth (median)**
Enbridge Inc.	0.333	0.129	0.080
TransCan Corp.	0.102	0.392	0.128
Emera Inc.	0.169	0.237	0.096
Fortis Inc.	0.112	0.212	0.054
AltaGas Ltd.	0.269	0.118	0.151
Algonquin Power	0.536	0.167	0.404
Gaz Metro MLP	0.049	0.122	0.030
	CV (EBIT/Sales)	**EBIT/Sales**	**EBIT Growth**
Average	**0.224**	**0.197**	**0.135**
Median	**0.169**	**0.167**	**0.096**
Max	0.536	0.392	0.404
Min	0.049	0.118	0.030
StdDev	0.169	0.098	0.126
Wt Av	**0.234**	**0.202**	**0.093**

Table 23 provides the summary statistics for earned ROEs for the Canadian sample, identical to those provided for the Alberta utilities in Table 18 and the U.S. utilities in Table 21. The reported ROEs for the Canadian utilities are higher than for the Alberta utilities on average, with an average across all 7 utility averages of 10.5%, versus the corresponding figure of 9.31% across the Alberta utilities. This is a reflection of the fact that they own numerous companies involved in various activities, including international operations. In fact, this average is close to the U.S. average of 10.75% noted in Table 21. However, we also note that the individual utility averages fluctuate greatly from 3.78% for Algonquin to 15.76% for Enbridge Inc. In addition, if we look at the last column in Table 23 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the individual Canadian utilities to the results in the last column of Table 18 for Alberta utilities, we can see that the Canadian utilities displayed much greater volatility in ROEs than the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the Canadian utilities were 0.38 and 0.27 respectively, versus corresponding figures of 0.17 and 0.15 for Alberta utilities as reported in Table 18. These average and median CV(ROE) figures are similar to those reported for the U.S. utilities in Table 21 of 0.36 and 0.21, likely reflective of the fact that the Canadian sample firms are holding companies, similar to the U.S. firms. This analysis, similar to the analysis of CV(EBIT/Sales), suggests that the Canadian utilities' sample firms possess greater risk than Alberta utilities, but lower than the U.S. utilities sample.

TABLE 23

SUMMARY STATISTICS – CANADIAN REPORTED ROES (2005-2014)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Enbridge Inc.	15.76%	14.81%	25.78%	9.18%	5.45%	0.346
TransCan Corp.	12.41%	11.20%	18.42%	8.36%	3.39%	0.273
Emera Inc.	11.27%	11.69%	15.12%	7.45%	2.97%	0.264
Fortis Inc.	9.18%	8.75%	12.40%	5.45%	2.01%	0.219
AltaGas Ltd.	13.26%	11.50%	22.70%	3.90%	6.44%	0.486
Algonquin Power	3.78%	5.05%	7.26%	-4.65%	3.59%	0.949
Gaz Metro MLP	7.61%	7.44%	8.84%	6.27%	0.83%	0.109
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**10.47%**	**10.06%**	15.79%	5.14%	3.53%	**0.378**
Median	**11.27%**	**11.20%**	15.12%	6.27%	3.39%	**0.273**
Max	15.76%	14.81%	25.78%	9.18%	6.44%	0.949
Min	3.78%	5.05%	7.26%	-4.65%	0.83%	0.109
StDev	3.97%	3.22%	6.92%	4.67%	1.92%	0.277

Overall, we can see that the Canadian utilities in this group display greater operating income volatility than Alberta utilities, but less than the U.S. utilities. The Canadian utilities also display lower EBIT/Sales ratios than Alberta utilities and similar growth in EBIT, but higher profit margins and growth than the U.S. utilities. Finally, they display higher ROEs but greater volatility in ROEs than Alberta utilities, similar to the U.S. utilities. This analysis indicates suggest that the Canadian utilities represent "better" comparables for Alberta utilities, but they are not ideal, mainly because they are holding companies, and we are trying to examine operating utilities. I have identified some issues arising from this dilemma above with respect to the use of Algonquin and Enbridge Inc. I also noted that Gaz Metro was probably a better comparable since it was comprised of three operating distribution companies. With respect to the remaining four utilities included in Tables 22 and 23, Fortis Inc. and Emera Inc. are diversified holding companies that are comprised of numerous companies involved in distribution, transmission and generation, as well as other activities. Fortis Inc. derives almost 39% of its revenue outside of Canada, while Emera Inc. derives 47%, according to the response to UCA-Utilities-2016FEB18-034. TransCan Corp operates pipelines throughout North America and derives 48% of its revenues outside Canada, while AltaGas Ltd. is heavily engaged in generation and generates 34% of its revenues outside Canada.[36] Hence, it is important to be aware of these differences.

4.3.5 Conclusions About Alberta Utilities' Risk Versus Comparables

The discussion above shows that it is difficult to find available information on ideal comparators for analysis purposes. However, some important conclusions have arisen. First, U.S. holding companies are poor comparators, since they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk. Secondly, Canadian utilities are better, yet still imperfect comparators, since public information is generally available for holding companies and not for operating companies. Finally, and perhaps most importantly, Alberta utilities possess low business risk. My quantitative analysis confirms this fact, which supports Mr. Stauft's conclusions and the long-standing business risk assessment of Alberta utilities by debt rating agencies.

Given the significant issues with using U.S. comparables, I have used only Canadian utilities in both my CAPM and DCF analysis, while recognizing their limitations. For example, given the comparability issues involved, I note that I do not actually use the individual beta estimates

[36] The sources of non-Canadian revenue quoted in this sentence are both according to the response to UCA-Utilities-2016FEB18-034.

provided in Table 8. If I did, my beta estimates for Alberta utilities would have been much lower. I used averages across the utilities in my DCF analyses to try and mitigate potential comparability issues, and more importantly I use my market DCF estimates (which I consider to be more reliable) as a reasonableness check on the results.

4.4 Financial Risk and Credit Metrics

Section 4.3 shows that Alberta utilities have earned ROEs at or above their allowed ROEs for the last 9 years, and that they have done so with low volatility in these earned ROEs. These facts suggest that they possess low total risk, which is a function of both business risk and financial risk.

The allowed equity ratios (ERs) in the 2013 AUC Decision ranged from 36% (for ATCO Electric Transmission, Altalink, ENMAX Transmission and EPCOR transmission), to 42% for AltaGas. Mr. Stauft's evidence shows that the EBIT coverage ratio, the FFO coverage ratio and the FFO/Debt ratios associated with an ER of 36% and at the existing ROE of 8.3% would be 2.22, 3.43 and 11.89 respectively. These ratios exceed the AUC's thresholds of 2.0, 3.0 and 11.1%-14.3% very comfortably. This statement would also be true if the minimum ER was reduced to 35%, which produces ratios of 2.17, 3.36 and 11.58% respectively. Finally, Mr. Stauft's sensitivity analysis shows that the metrics for Alberta utilities would exceed the minimum AUC values if the ER was reduced to 35% and the allowed ROE was reduced to 7.5% - with EBIT coverage of 2.05, FFO coverage of 3.28 and FFO/Debt of 11.17%.

Given my conclusions regarding the low business risk possessed by Alberta utilities, and the metric analysis above, it is feasible for the Board to reduce the equity ratio to 35%, while maintaining the financial integrity of the utilities.

4.5 Capital Structure Recommendation

The utilities' evidence argues that Alberta utilities possess similar risk to their U.S. and Canadian utility samples, except for the UAD Decision, which means they may have more risk. For example, on page 38, lines 3-4 of her evidence Dr. Villadsen states: "Therefore, the US Electric sample companies may have lower risk than the Utilities…" In her response to UCA-Utilities-2016FEB18-038, Dr. Viladsen indicated that she "was referencing the UAD decision here…"

I disagree with such statements at two levels. First, my evidence clearly shows that Alberta utilities have much less risk than the U.S. utilities groups presented in the utilities evidence, and that they possess marginally less risk than their Canadian utilities groups. Secondly, I do not believe that the UAD Decision created a significant risk to the Alberta utilities of anywhere near the magnitude that is argued by the utilities. Therefore, I do not see good reason to increase equity ratios.

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk it is not surprising that they have been able to generate ROEs at or above the allowed ROEs for the last 9 years consecutively, and that these ROEs displayed low volatility. My analysis of the global, Canadian and Alberta economies suggests that economic and capital market conditions have stabilized and are far removed from the conditions existing in 2009 when the Board provided a 2% across the board increase in equity ratios. The Board removed 1% of this buffer in its 2013 Decision, and I recommend that they remove the other 1% in this Decision. In other words, I am recommending a reduction in the equity ratio of 1% across the board. My risk analysis suggests this is reasonable, and the credit metric analysis provided by Mr. Stauft shows that such a reduction would leave credit metrics within the desired metric ranges according to criteria used by the Board, and by debt rating agencies.

5. ROEs AND CAPITAL STRUCTURE

One way to illustrate the relationship between ROEs and equity ratios is to use the DuPont system for decomposing ROE into basic components. The standard 3-point decomposition formula breaks ROE into three financial ratios which are considered important by analysts examining company performance. These ratios are: the net income margin (net income dividend by sales, or NI/S); the asset turnover ratio (total sales divided by total assets, or S/TA); and, the leverage ratio (total assets divided by total equity, or A/E). Since ROE is defined as net income divided by total equity, or NI/E, we can see the multiplying the three ratios above by one another leaves us with NI/E or ROE. This equation is presented below:

$$ROE = NI/S \times S/A \times A/E$$

Since the product of the first two terms reduces to NI/A, or the return on assets (ROA), it is also common to observe that ROE = ROA × A/E, which is convenient for my discussion.

I begin by noting that a higher leverage ratio (A/E) implies a lower equity ratio, and vice-versa. Non-regulated firms will typically try to choose a leverage ratio that generates higher ROEs, while recognizing that higher leverage ratios generate additional financial risk, as reflected in greater volatility in ROEs, all else being equal. However, regulated utilities earn higher NI if they have a higher ER (i.e., lower A/E) since they earn the allowed ROE on this higher equity dollar figure. Of course they should also earn higher ROEs if they are awarded higher allowed ROEs. So regulated utilities prefer both higher allowed ROEs and higher ERs. Not only do the utilities earn higher net income if they have higher allowed ERs, it also reduces their financial risk and the associated volatility in ROEs, all else being equal. Of course this additional net income and reduction in earnings volatility comes at the expense of consumers, as reflected in their rates.

I would note that my analysis in Section 3 shows that Alberta utilities have low business risk, as reflected by volatility in operating income, and that they also maintain low total risk as reflected in both their ability to earned allowed ROEs and the low volatility in those earned ROEs. As Mr. Stauft mentions in his evidence, the holding companies of many of the Alberta regulated utilities maintain equity ratios at the holding company level that are lower than at the regulated operating company level.[37] This makes sense to me since they can increase their earned ROEs by doing so (as long as ROA remains positive), as long as they are comfortable with the additional volatility in ROE. Given the low volatility in both operating income and earned ROEs that I have noted, it seems reasonable that additional volatility is not problematic.

[37] For example, Mr. Stauft notes that Canadian Utilities Ltd. has an equity ratio of 32%, Fortis Inc. has an equity ratio of 36%, and AltaLink Investments has a consolidated common equity ratio of about 27%.

The discussion above supports the notion that the AUC approach of setting one allowable ROE for utilities and then adjusting the allowed ERs to vary according to risk levels relative to the "average" utility is a logical approach. The granting of higher ERs to utilities deemed to have greater business risk, appropriately reduces the financial risk of such utilities. Since total risk is a function of both business and financial risk, such a process is a useful mechanism for controlling total risk.

This concludes my testimony.

Attachment 3: Alberta GCOC proceedings in 2018 (AUC Proceeding ID 22570)

ALBERTA UTILITIES COMMISSION

2018 GENERIC COST OF CAPITAL

PROCEEDING ID #22570

EVIDENCE OF DR. SEAN CLEARY, CFA, BMO PROFESSOR OF FINANCE

Submitted on behalf of:

The Office of the Utilities Consumer Advocate

January 12, 2018

TABLE OF CONTENTS

1. INTRODUCTION

1.1. Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am currently the BMO Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta (the **"UCA"**) on several occasions including generic cost of capital ("**GCOC**") proceedings in 2013-2014 (Proceeding ID 2191) and 2015-2016 (Proceeding ID 20622), as well as the generic regulated rate option ("**RRO**") proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan (Proceeding ID 22357) in 2017. I also testified on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of 30 publications. My work has been cited close to 3,000 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of equity issues. I have authored or co-authored 13 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Appendix A to my evidence.

1.2. Purpose of Testimony

With respect to the 2018 GCOC Proceeding in Alberta, the UCA has requested that I provide recommendations regarding the appropriate return on equity ("**ROE**") and equity ratios for Alberta utilities. I acknowledge that I have a duty to provide opinion evidence to the Alberta Utilities Commission (the "**Commission**" or "**AUC**") that is fair, objective and nonpartisan.

1.3. Summary of ROE Estimates

Section 2 shows that global economic conditions are solid and have improved since the time of the 2016 GCOC Proceeding, and the same can be said of Canadian capital market conditions. Canadian economic growth exceeded expectations during 2017 at an estimated pace of 3% growth in real GDP, while Alberta's 2017 real GDP growth is estimated at 6.7%. Both Canada and Alberta are expected to experience more moderate but solid GDP growth going forward. Bond yield spreads have declined, as has stock market volatility, and both bond and stock markets are healthy. In other words, economic and capital market conditions are solid today, improved since 2016, and far removed from those existing at the peak of the 2008-2009 financial crisis. Regardless, mature, regulated utilities operating in established territories are not influenced by economic cyclicality to the extent of traditional businesses. My evidence confirms this is true for Alberta utilities.

Several approaches were used to estimate the appropriate generic ROE for Alberta utilities including the Capital Asset Pricing Model ("**CAPM**"), Discounted Cash Flow ("**DCF**") and Bond Yield Plus Risk Premium ("**BYPRP**") models. Based on an equal weighting of these three approaches, I estimate the following best estimate and ranges for an appropriate ROE:

Year	CAPM (1/3rd)	DCF (1/3rd)	BYPRP (1/3rd)	Overall Range	Best Estimate
2018 2019	5.5%	6.9%	6.5%	4.0-8.2%	**6.3%**

The details of all estimates are provided herein, as is the reason for choosing an equal weighting scheme.

This estimate is very reasonable when compared to current expectations of market professionals for long-term overall stock market returns in the range of 6-9% (with a best estimate of 7.5%) , when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 6-9% range are consistent with experienced long-term real stock returns of 5.6-7.4%. The ROE estimate is also consistent with our current low interest rate environment, which can be expected to change only gradually over the next few years.

1.4. Summary of Comments on Capital Structure

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk, it is not surprising that they have been able to generate ROEs above the allowed ROEs for the last 11 years, exceeding the allowed ROE by an annual average (weighted average) of 0.64% (0.97%) over the 2005-2016 period, as I will discuss further below. My analysis also shows that these earned ROEs displayed very low volatility, indicating low total risk.

Combining this risk analysis with my positive economic and capital market outlook, I am recommending no change in allowed equity ratios, but rather emphasize the impetus for a reduction in the allowed ROE. My analysis suggests these recommendations are reasonable, and the credit metric analysis provided by Mr. Bell supports this recommendation.

2. THE ECONOMY AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE

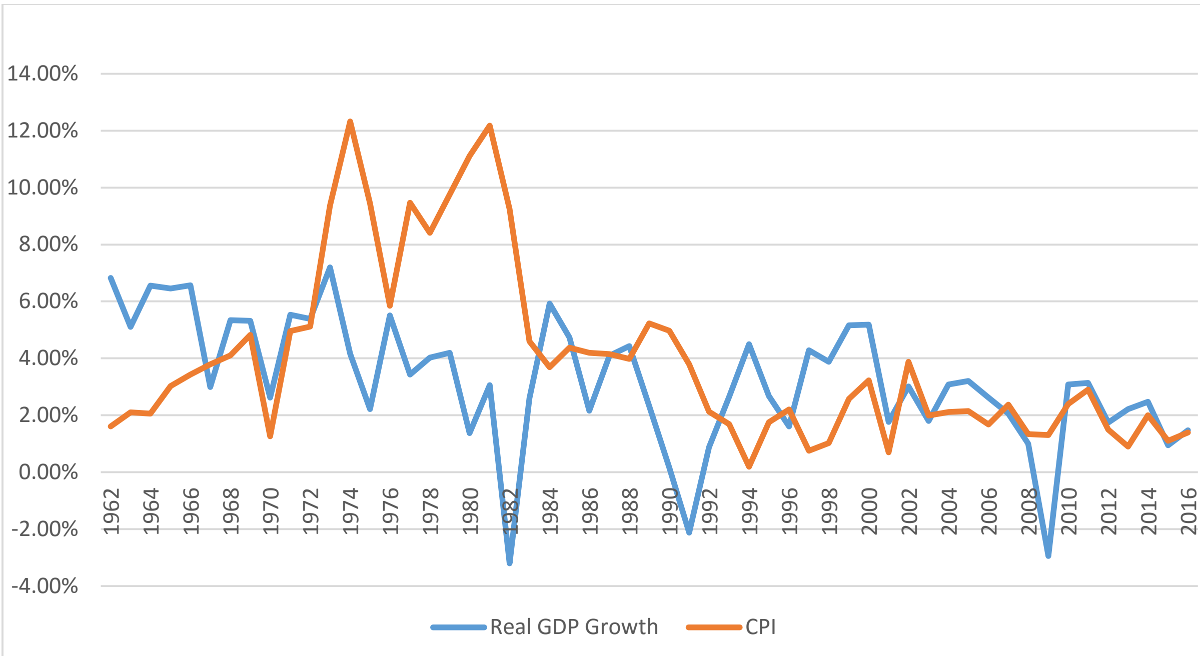
2.1. The Past and Present

2.1.1. Historical Evidence

Figure 1 below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index ("**CPI**") over the 1962 to 2016 period. The graph shows that real GDP growth has generally been in the 2-6% range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average GDP growth over the entire period was 3.2% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.5% (median 2.6%) over the 1992 to 2016 period. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from Figure 1, and also as measured by the standard deviation reported in Table 1. The working papers for Figure 1 and Table 1, below, are appended as Exhibit A to my evidence.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2016)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2016)

	1962-2016 (%)		1992-2016 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.21	3.96	2.46	1.81
Median	3.08	3.03	2.62	1.75
Max	7.20	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.24	3.11	1.66	0.84

Data Source: Statistics Canada.

The 1962-2016 stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average CPI of 1.81% (median 1.75%). CPI growth has also been very stable during this latter period, which is obvious from Figure 1, and also by the huge decline in standard deviation from 3.1% over the entire 1962-2016 period to 0.8% since 1991. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2. Changes since the 2016 Decision

In Decision 20622-D01-2016 (the "**2016 GCOC Decision**"), the Commission stated:

> The Commission's view is that there is no definitive evidence on the record to explain the increased credit spreads, and accordingly it could be the result of a combination of factors. If there is no clear rationale for the increase in credit spreads, then the Commission cannot conclude that the widening of credit spreads indicates increased risk perceptions among Canadian utility bond investors and by extension, Canadian utility equity investors. Equally, the Commission cannot conclude that the widening of credit spreads does not indicate, at least in part, increased risk perceptions among utility bond and equity investors.[1]

The Commission went on to state:

> Based on Figure 5 above and considering the evidence of the parties with respect to market volatility, the Commission considers it reasonable to conclude that recent instability in estimators of investor perceptions of near-term market uncertainty, including the VIX and the VIXC, are indicative of increased investor uncertainty in the 2016-2017 period compared to investor uncertainty which existed at the time of the 2013 GCOC proceeding.[2]

In other words, at the time of its 2016 GCOC Decision, the Commission felt investor uncertainty was slightly elevated relative to 2013 levels. This opinion was based on the possibility (not certainty) that elevated yield spreads indicated elevated risk perceptions, as well as by the higher levels of VIX and VIXC that prevailed in 2016, among other factors.

[1] Decision 20622-D01-2016, 2016 Generic Cost of Capital, page 21, para. 89.
[2] *Ibid.*, para. 91.

It is worth noting that the Commission had noted in Decision 2191-D01-2015 (the "**2013 GCOC Decision**") that:

> All parties agreed that current global economic and Canadian capital market conditions have improved since the time of the 2011 GCOC proceeding resulting in Decision 2011-474. The parties, however, disagreed on the amount of risk remaining in capital markets.[3]

So, in other words, overall, economic and capital market conditions were better during the 2013 GCOC Proceeding than during the previous 2011 GCOC Proceeding and the subsequent 2016 GCOC Proceeding.

During the 2016 GCOC Proceeding, the Consensus Economics Inc. ("**Consensus")** January 2016 forecasts of Canadian GDP growth for 2016 and 2017 were 1.8% and 2.0% respectively, while the Bank of Canada's January 2016 *Monetary Policy Report* ("**MPR**") anticipated slightly lower GDP growth rates at 1.4% and 1.9% for 2016 and 2017. In fact, real GDP growth turned out to be well above these forecasts – at 2.0% in 2016, and at 3.1% in 2017 (as estimated in the Bank of Canada's October 2017 MPR, appended as Exhibit AA to this evidence).

As a result of this strength in the Canadian economy during 2016 and 2017, the Bank increased its overnight lending rate in July 2017 and September 2017, so that it now sits at 1%. These increases essentially reversed the two decreases the bank implemented during the first half of 2015 in response to slower than expected growth. At the other end of the yield curve, Canadian long-term government bond yields increased approximately 50 basis points ("**bp**") in the month following the unexpected election of U.S. President Donald Trump in November 2016 (i.e., from 1.9% to 2.4% by mid-December), and has remained in the 2.0-2.5% range ever since. During November and December 2017, the 30-year Government of Canada yield has generally been in the 2.2-2.3% range, and it sat at 2.19% as of December 19, 2017 – a mere 4 bp above the level at which it ended in 2015 (i.e., 2.15%).

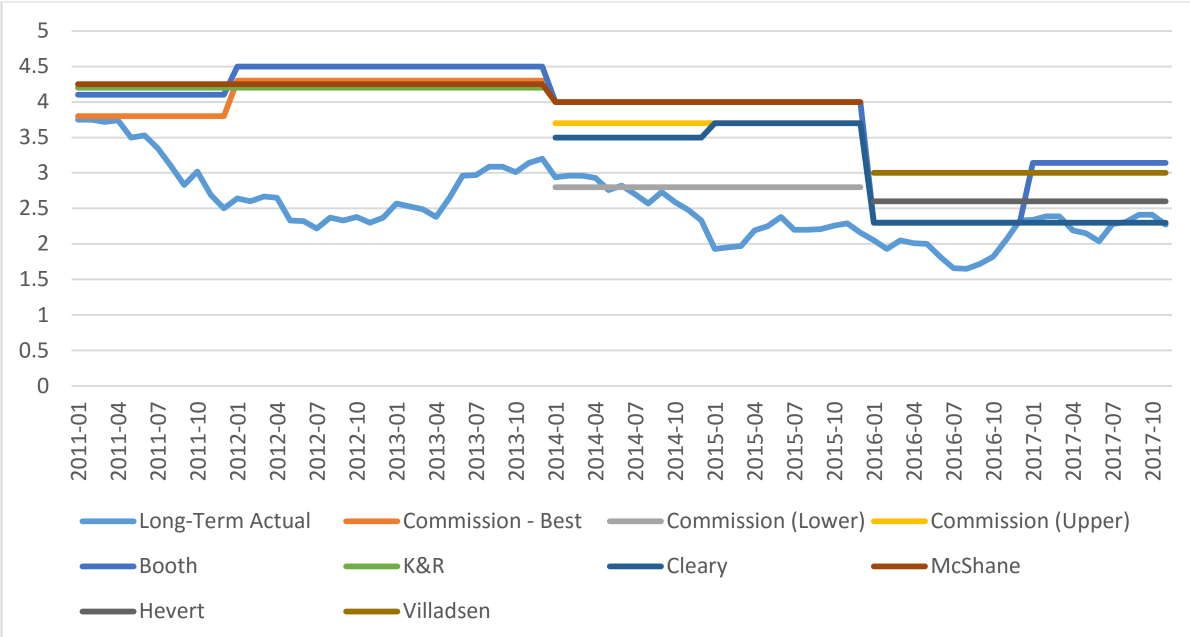
[3] Decision 2191-D01-2015, 2013 Generic Cost of Capital, page 6, para. 37.

During the 2016 GCOC Proceeding, I relied upon the January 2016 Consensus forecasts for government 10-year yields, which were 1.7% for April 2016 and 2.1% for January 2017. I then added the long-term average spread between 10-year and 30-year government yields of 50 bp to arrive at Consensus-based estimates for 30-year government bond yields of 2.2% and 2.6% for April 2016 and January 2017 respectively.[4] Noting that forecasts had consistently been too high in previous decisions, and consistent with the approach used by the Commission in its 2013 GCOC Decision, I used the actual prevailing long-term yield at the time of 2% as a lower bound, and used the 2.6% Consensus-based estimate noted above as my upper bound. I then used the 2.3% mid-point as my base case long-term Canada government bond yield estimate for 2017. This turned out to be very appropriate as the average 30-year government yield from January 1, 2017- November 15, 2017 was 2.29%. No doubt this estimate would have turned out to be too high had it not been for the unexpected election of Donald Trump. This is because my estimate was biased upwards by the influence of Consensus estimates which turned out to be too high, just as they had been during the time periods involved during previous proceedings. This is precisely why it is beneficial to use existing rates as a floor (or ceilings, in the case where Consensus-based forecasts indicate declines from prevailing yields). In other words, forecasters are often wrong, while existing rates offer the benefit of a starting point that reflects actual yields (i.e., yields that investors can actually achieve today), rather than forecasts which may or may not materialize. This is obvious when we look at Figure 2, produced below, which reports the estimates provided by all experts and the Commission in the 2011, 2013 and 2016 GCOC Proceedings, which were all well above the actual long-term government bond yields that materialized, with the exception of my 2016 forecasts which were close. The working papers for Figure 2 are appended as Exhibit B to my evidence.

[4] During the 2016 GCOC Proceeding, the utilities criticized my use of this long-term "average" maturity yield spread rather than the using the existing 76 bp spread at the beginning of 2016. This spread now sits at 26 bp as can be seen later in Figure 9.

FIGURE 2

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2011-2017)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

If we focus on the far right portion of Figure 2, we observe the 2016-2017 actual yields versus the forecast yields. I would note that in the 2016 GCOC Decision, the Commission did not provide a specific forecast that it had relied upon which could be included in Figure 2, but rather it indicated:

> Based on the foregoing, the Commission notes that although the prevailing risk-free interest rate is lower than at the time of the 2013 GCOC decision, general expectations are that interest rates will rise during the 2016-2017 period. Uncertainty remains, however, regarding the speed and magnitude of the expected interest rate increases.[5]

Figure 2 shows that the 2016-2017 forecasts that relied primarily upon Consensus Forecasts in one form or another (i.e., Booth, Hevert and Villadsen) and ignored existing yields were too high. In contrast, my 2016-2017 forecasts were closer to actual results, since they were based on a 50% weighting of prevailing yields in 2016, in addition to Consensus forecasts. Not coincidentally, my forecasts were also much more accurate than my forecasts made

[5] Decision 20622-D01-2016, 2016 Generic Cost of Capital, page 31, para. 133.

during the 2013 GCOC Proceeding, which relied solely upon Consensus forecasts, and ignored the level of prevailing rates at that time.

During the 2013 GCOC Proceeding, it was noted that yield spreads had declined significantly from their previous abnormal high levels during the 2009 GCOC Proceeding, but remained somewhat elevated at around 140. This spread was noted to be above the long-term average spread of around 100 bp, but well below the peak levels of around 300 bp in 2008-2009. During the 2016 GCOC Proceeding, the utilities' witnesses spent a lot of time discussing the importance of "elevated" yield spreads as an indicator of elevated risks. The A-rated utility spreads were around 200 bps at the time their evidence was prepared in the 2016 GCOC Proceeding; although they had declined to 170 bps by the end of May 2016.

Despite the obvious importance of the total cost of borrowing to utilities, the initial evidence provided by the utilities' experts during the 2016 GCOC Proceeding did not discuss the important fact that the total yields (i.e., their cost of long-term debt) at which the utilities could borrow were actually lower in 2016 than in 2013. Ultimately, the utilities' experts were forced to acknowledge this fact in response to information requests and/or under cross examination. The decline in utility borrowing rates in 2016 was of course due to the decline in government yields, which more than offset the increase in yield spreads. In contrast, I noted this important fact in my evidence in the 2016 GCOC Proceeding:

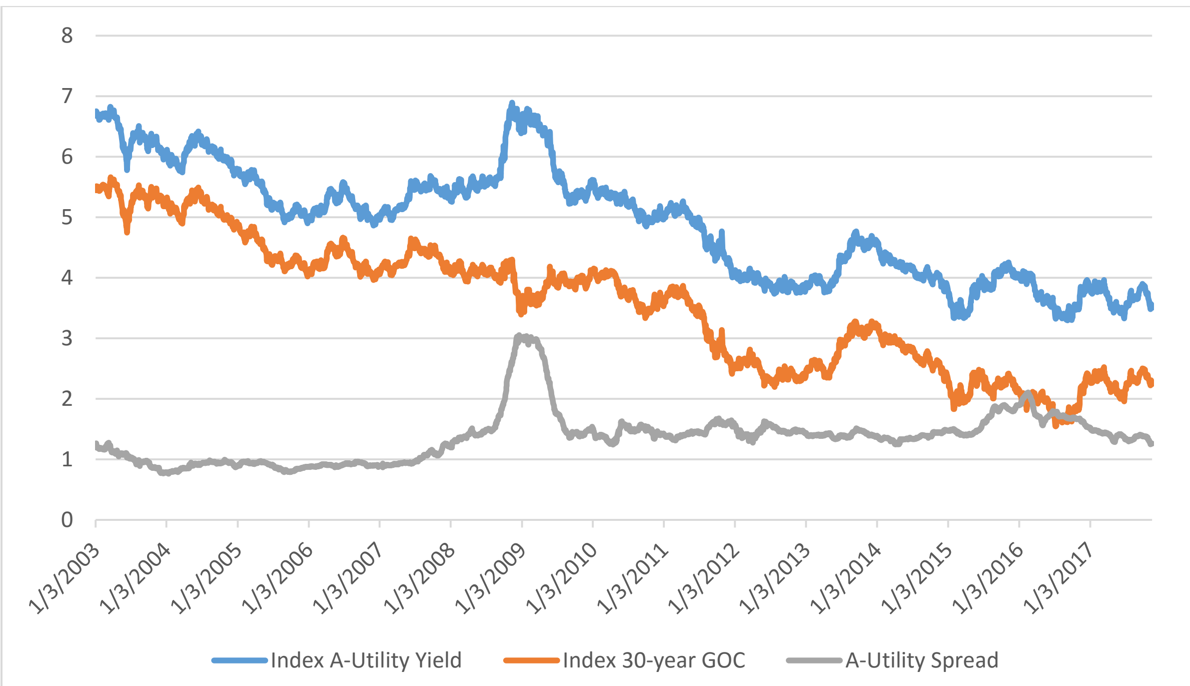
> Despite this increase in yield spreads, the cost of long-term borrowing to A-rated utilities has actually declined since 2013. For example, the average yields were 4.24% and 4.14% during 2013 and 2014, years during which the corresponding yield spreads averaged 1.41% and 1.37% respectively. During 2015, the average yield for A-rated utility bonds was lower at 3.82%, despite a higher average yield spread of 1.63%. While the yield spread had increased to 1.90% by the end of 2015 and to 2.06% by February 3, 2016, the yields on A-rated utility bonds were actually lower than in 2013 and 2014 at 4.05% in December 2015 and 4.03% on February 3, 2016 – of course this is due to the decline in risk-free government bond yields, which form the base rate for utility borrowing.[6]

[6] Exhibit 20622-X0306, Evidence of Dr. Sean Cleary, page 9, lines 4-12.

The opposite offsetting movements in government yields and yield spreads have occurred since the 2016 GCOC Proceeding, which is obvious in Figure 3. In particular, we can see that yield spreads have declined since 2016 (to 1.26% by November 15, 2017), while government yields have increased (to 2.25% by November 15, 2017). The net result of these two changes was a decrease in A-rated Utility bond yields to 3.51%, 52 bp lower than when I prepared my evidence in the 2016 GCOC Proceeding, and 18 bp below the May 30, 2016 level of 3.69%, which was prevailing around the time of the oral hearing in 2016. The working papers for Figure 3 are appended as Exhibit C to my evidence.

FIGURE 3

A-UTILITY YIELDS (January 1, 2003-November 15, 2017)



Source: Bloomberg.

The fact that yield spreads declined and government yields increased as economic and capital market conditions improved is consistent with the argument that I advanced in my evidence in the 2016 GCOC Proceeding:

> It is reasonable to assume that as economic and capital markets gradually return to a more typical state that A-rated utility yield spreads will experience a gradual reduction from their current 2% level to around 1%. This 100 bps decrease would offset to a great extent by the

> expected increase in 10-year (and long-term) government yields of 70 bps during 2016, and another 40 bps in 2017. Of course, if some of the uncertainties identified earlier persist or get worse, these spreads may not return to normal levels, or may do so much slower than expected, so it is not a given. However, under such circumstances, it is unlikely that government yields would increase as much as expected – so changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent.[7]

In fact, the correlation coefficient between long-term government bond yields and A-rated Utility yield spreads over the January 2003-November 2017 period was -0.49, which indicates a strong negative relationship – exactly as logic would dictate, and as I have argued.

Of course, the evidence of the utilities filed in the current proceeding does not give much attention to this decline in yield spreads (i.e., 80 bp decline since February 2016). Instead, the evidence now focuses on the increase in government yields (i.e., 28 bp since February 2016), which of course has occurred due to improved economic and capital market conditions. In doing so, they are once again ignoring one of the two important components that comprise utility bond yields.

Regardless whether one focuses on yield spreads, on underlying government bond yields, or on both (as should be the case), it is obvious that the cost of long-term borrowing for A-rated Canadian utilities, as measured by long-term bond yields, remains extremely low. This is true in both absolute terms and relative to historical borrowing costs. This implies that the cost of equity for A-rated utilities is also low in both absolute and relative terms, since a company's cost of equity is linked to its cost of debt.[8]

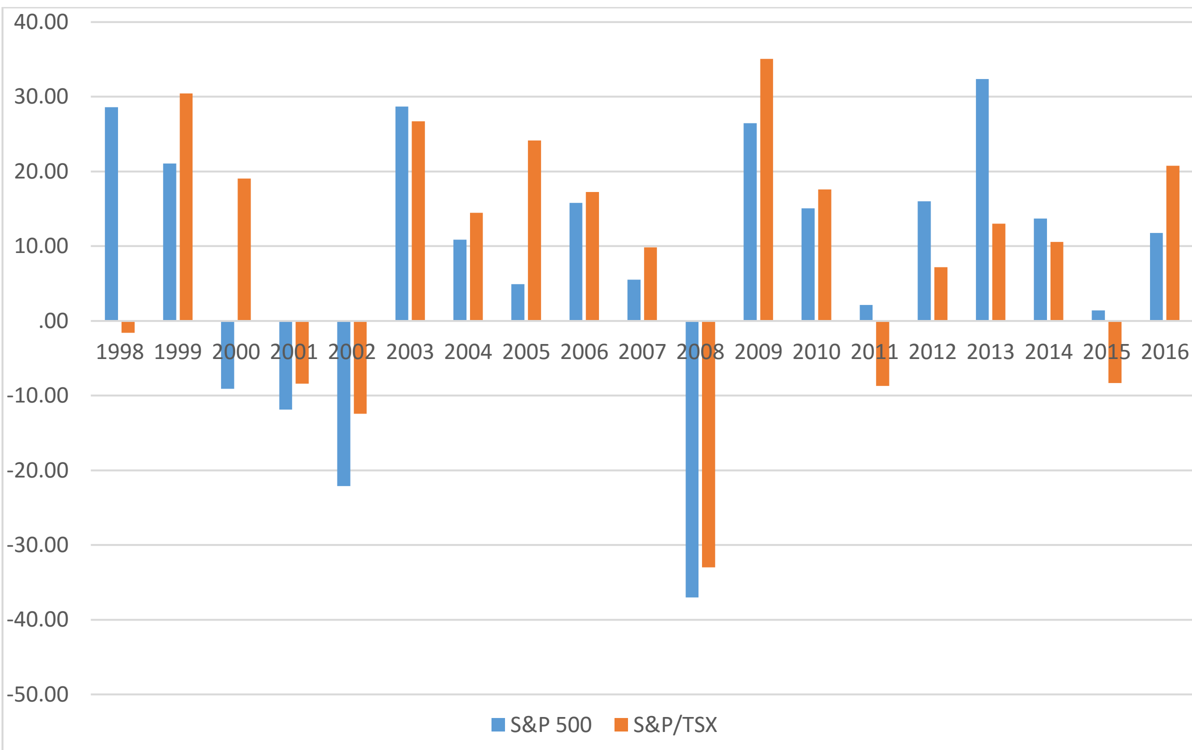
The Canadian stock market had an excellent year in 2016, providing an average total return of 20.8% in 2016, while U.S. markets also had a good year, providing an average return of 11.8%. As of December 20, 2017, the return on U.S. stock markets was 19.7%, while the Canadian market return was 5.7%. Figure 4 provides the average annual total stock returns for Canada and the U.S. over the 1998-2016 period. Over this period, stocks in Canada provided an average return of 9.1% (geometric mean of 7.7%), while U.S. stocks provided an

[7] *Ibid.*, page 27, lines 1-9.
[8] For example, this link is very clear in the widely used BYPRP approach, which will be discussed in detail in Section 3.3.

average return of 8.1% (geometric mean of 6.5%). These figures are low relative to longer term historical nominal averages; however, they are consistent with long-term "real" stock returns in the 6.2% to 7.4% range, and current market expectations (both of which are discussed in Section 2.3.3) that are based on lower inflation expectations over more recent periods, as monetary authorities around the globe have strived to maintain inflation levels in the area of 2%. The working papers for Figure 4 have been appended as Exhibit D to my evidence.

FIGURE 4

STOCK MARKET RETURNS - (1998-2016)



Source: Bloomberg

The trailing price-earnings ("**P/E**") ratio for the S&P/TSX Composite Index stood at 19.6 on November 24, 2017, while the P/E ratio for the U.S. S&P 500 Index was 21.9 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below 15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 19 to 22 range in Canada and the U.S. are in familiar territory; albeit slightly elevated especially in the case of the U.S. As at November 24, 2017, dividend yields were 1.9% in the U.S. and 2.7% in Canada, also within typical ranges.

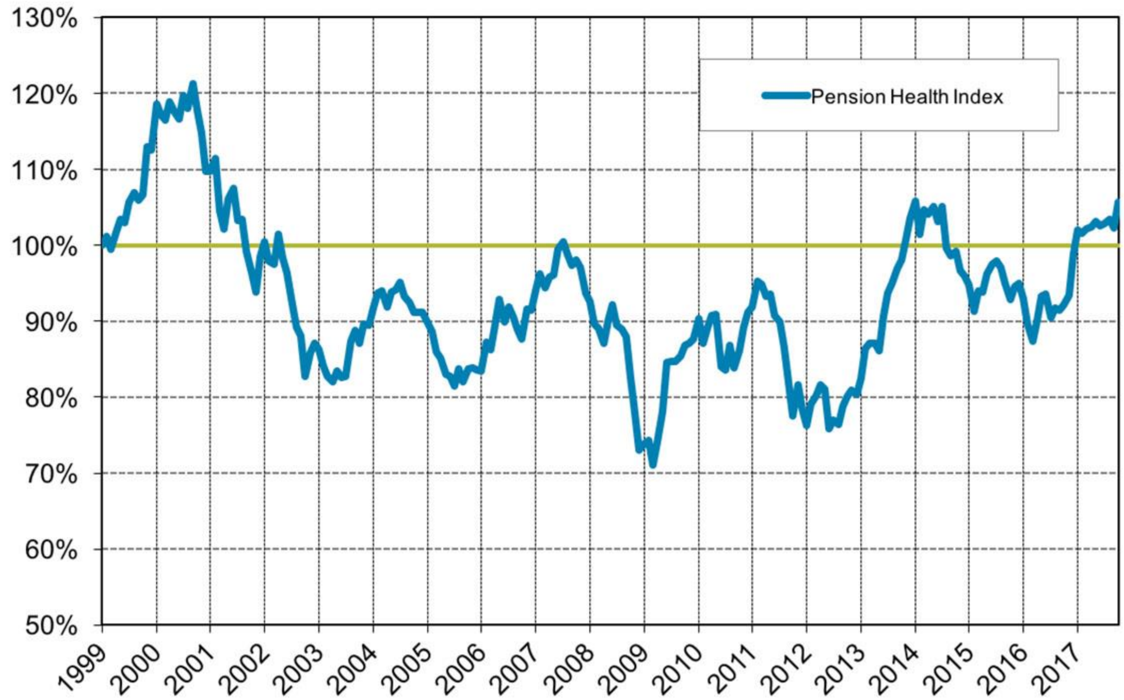
The implied volatility indexes in Canada and the U.S. have averaged in the 16-20 range through time.[9] The Canadian and U.S. VIX indices stood at 10.6 and 9.7 respectively as of December 20, 2017, indicating well below normal volatility in both Canada and the U.S. The current levels are dramatically lower than those that existed at the start of the 2016 GCOC Proceeding and are well below long-term averages. During the 2016 GCOC Proceeding, the utilities' experts stressed that elevated volatility index levels (in the 26 to 40 range) represented a major indicator of elevated levels of risk in equity markets. However, in the current proceeding, the utilities' experts fail to acknowledge that the converse is true – i.e., lower levels could indicate lower levels of risk. Instead, they merely point out that this is a short-term volatility measure.

Finally, pension fund health is a closely watched and important financial health indicator. Poor stock returns during the crisis, combined with extremely low levels of interest rates, hit the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall Canadian pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 5 depicts the value of this index over the 1999 to 2017 period. The index ended September of 2017 at 106%, up from 102% at the start of 2017, and well above the level of 95% at which it sat in January of 2016, when I prepared my evidence for the 2016 GCOC Proceeding. The continuous improvement since 2016 is a result of increases in long-term bond yields and solid Canadian and U.S. equity market performance. The current level of 106% represents an 11% improvement over the January 2016 level of 95%, is comfortably above 100%, and is well above the all-time low of around 70% in early 2009. Hence, this measure of financial stability indicates improving and solid market conditions, which are better than those existing during the 2016 GCOC Proceeding, and which are nowhere near crisis levels.

[9] According to Mr. Hevert's evidence, the U.S. index has averaged 19.5 since 1990, while the current Canadian index has averaged 16.6 since its inception in 2009.

FIGURE 5

MERCER PENSION HEALTH INDEX - (1999-2017)



Source: https://www.mercer.ca/en/newsroom/defined-benefit-pensions-edge-up-in-q3-2017.html, December 20, 2017.

2.2. The Future

2.2.1. Global Economic Activity

The global economy has faced several challenges since 2008, but is expected to grow at solid rates in 2017 and 2018. For example, Table 2 shows the October 2017 Consensus forecasts for average global real GDP growth figures of 3.1% for both years, while the Bank of Canada's October 2017 MPR estimates were slightly higher at 3.4% for both years. Table 2 shows that the expected global improvements are based in large part on expectations that the U.S. economy will continue to grow steadily over 2017 and 2018 in the 2.2-2.4% range, while the Euro zone will continue to rebound back to more normal growth levels with expected growth rates of 2.2% for 2017 and 1.8% for 2018.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2017-2018)

Real GDP Growth (%)	2017		2018	
	Consensus	Bank of Canada	Consensus	Bank of Canada
World	3.1	3.4	3.1	3.4
U.S.	2.2	2.2	2.4	2.2
Euro Zone	2.2	2.3	1.8	1.8

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

The Bank of Canada notes several factors contributing to its solid global growth projections in its October 2017 MPR, which is appended as Exhibit AA to this evidence. These factors include: accommodative global financial conditions; moderate growth in the U.S. economy; improving growth in the Euro zone; inflation continuing to track below targets in advanced economies; emerging markets continuing to drive global growth (noting stronger than expected growth in China in particular); and, increases in oil and commodity prices.

2.2.2. Canada's Outlook

The Bank of Canada noted in its October 2017 MPR, appended as Exhibit AA, that Canadian economic growth was rapid during the second quarter of 2017, exceeding expectations. This growth was robust on several levels – across regions, industries, individual consumption, business investment, and export growth. As a result, the Bank estimates that excess capacity declined faster than expected and the Bank estimates the output gap to be between -0.5 to +0.5 percent. This means the economy is operating at or near capacity.

Going forward, the Bank expects solid growth to continue, but at a more moderate and sustainable level. This growth will be supported by several factors, including: rising foreign demand; firming of commodity prices; accommodative monetary and fiscal conditions; improved contributions from exports; and, continued steady business investment. Their growth projections are also reflective of a decline in the contribution to total growth from consumption and residential investment. The Bank notes that its forecast incorporates the most recent increases in the Bank policy rate, as well as the recent appreciation in both the Canadian dollar and commodity prices.

As a result of their analysis, the Bank predicts real GDP growth of 3.1% in 2017, followed by growth rates of 2.1% in 2018 and 1.5% in 2019. Table 3 shows that the 2018 and 2019 forecasts are in line with the Consensus forecasts of 2.0% and 1.9%.

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2017-2019)

	2017	2018	2019
Conf. Board of Canada	2.6	1.9	
CIBC World Markets	3.0	2.1	
IHS Economics	3.1	2.3	
Citigroup	3.1	2.1	
BMO Capital Markets	3.1	2.2	
Desjardins	3.1	2.2	
Econ Intell Unit	3.0	1.9	
EconoMap	3.2	2.1	
Oxford Economics	3.0	2.0	
JP Morgan	3.1	1.8	
National Bank	3.0	2.5	
RBC	3.1	2.2	
TD Bank	3.1	2.2	
University of Toronto	2.9	2.1	
Scotia Econ	3.1	2.0	
Informetrica	3.1	2.1	
Inst Fiscal Studies	3.1	2.0	
Capital Economics	3.0	1.5	
Centre for Spatial Economics	2.8	1.9	
Average	**3.0**	**2.0**	**1.9**
Median	**3.1**	**2.1**	
Max	**3.2**	**2.5**	
Min	**2.6**	**1.5**	
IMF (Oct 17)	**3.0**	**2.1**	
OECD (Sept 17)	**3.2**	**2.3**	
Bank of Canada (Oct 2017)	**3.1**	**2.1**	**1.5**

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

Based on the discussion above, the Bank predicts that the economy will operate at close to capacity, but inflation will remain below target at 1.5% in 2017 and 1.7% in 2018, before increasing to 2.1%, slightly above target in 2019. The Bank's projections were slightly below the 2017 and 2018 Consensus forecasts of 1.6% and 1.9%, as well as with those of the IMF (1.6% and 1.8%), all of which can be found in Table 4.

TABLE 4

CPI FORECASTS – CANADA (2017-2018)

	2017	2018
Conf. Board of Canada	1.9	2.0
CIBC World Markets	1.6	2.1
IHS Economics	1.8	2.0
Citigroup	1.7	1.9
BMO Capital Markets	1.5	1.9
Desjardins	1.5	1.8
Econ Intell Unit	1.5	1.8
EconoMap	1.5	1.8
Oxford Economics	1.6	2.1
JP Morgan	1.5	1.9
National Bank	1.6	1.8
RBC	1.5	1.7
TD Bank	1.5	1.7
University of Toronto	1.5	2.1
Scotia Econ	1.5	1.9
Informetrica	1.6	1.9
Inst Fiscal Studies	1.3	1.8
Capital Economics	1.6	1.7
Centre for Spatial Economics	1.7	1.8
Average	**1.6**	**1.9**
Median	**1.6**	**1.9**
Max	**1.9**	**2.1**
Min	**1.5**	**1.6**
IMF (Oct 17)	**1.6**	**1.8**
Bank of Canada (Oct 2017)	**1.5**	**1.7**

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

Of course, there are several uncertainties associated with the projections above. The Bank discussed several key upside and downside risks to their inflation outlook, and suggested that these risks "to the projected path for Canadian inflations are roughly balanced." The noted risks are: (1) a shift toward protectionist trade policies and weaker Canadian exports; (2) a larger impact of structural factors and prolonged excess supply on inflation; (3) stronger real GDP growth in the United States; (4) stronger consumption and rising household debt in Canada; and, (5) a pronounced drop in house prices in overheated markets.

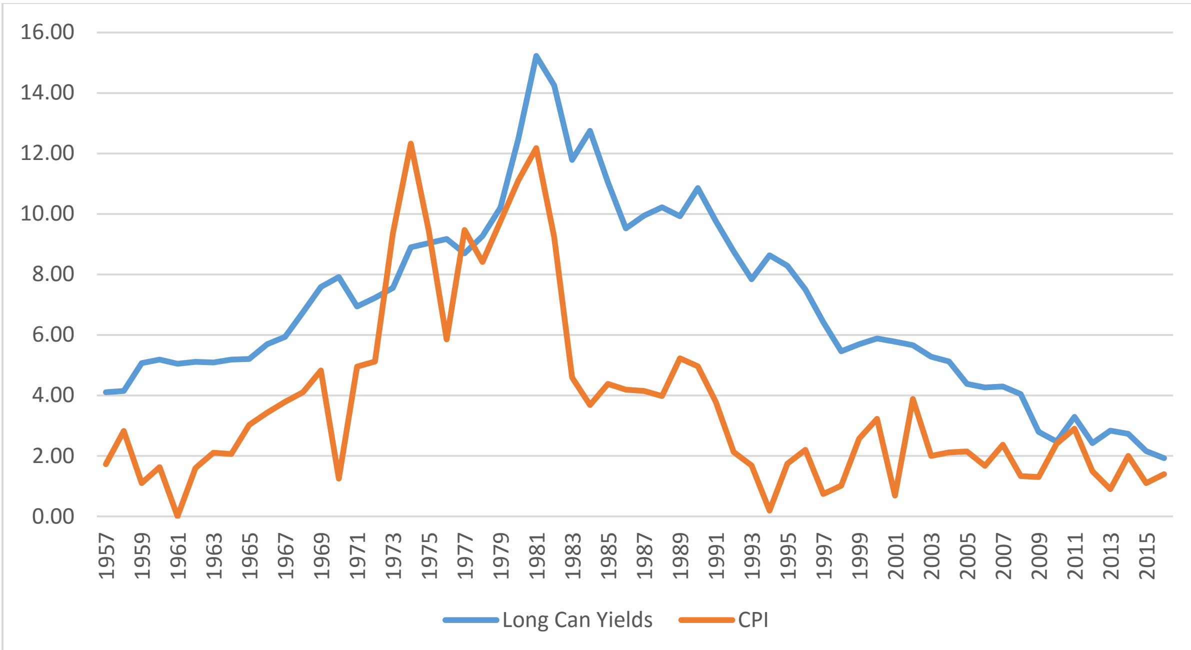
2.3. Capital Market Conditions and Expectations

2.3.1. Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 6 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation. Of course, yields are determined based on "expected" inflation, and we can see a few years in the 1970s where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since 1991 is obvious from the graph, with inflation hovering around the 2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 4.03%, with inflation averaging 1.92%. Not only have long-term Canada bond yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005.

FIGURE 6

BOND YIELDS AND INFLATION – CANADA (1957-2016)

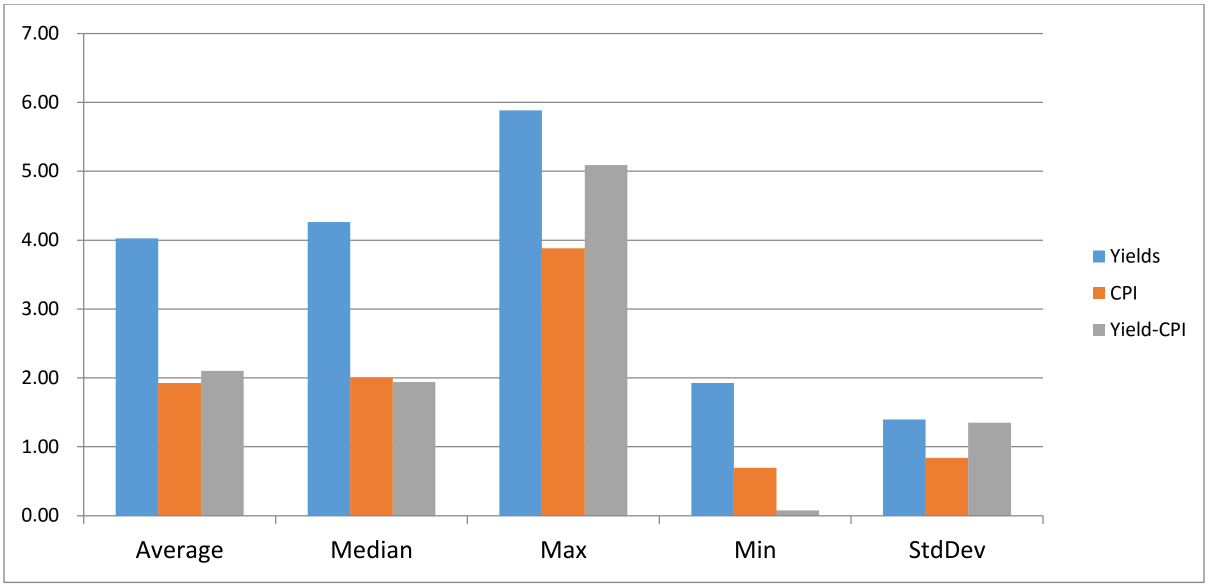


Data Source: CANSIM database.

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 6. This can also be seen in the standard deviations reported in Figure 7, which reports summary statistics for the 1998 to 2016 period. For example, the standard deviation of the yields was 1.39% over this period, versus 3.10% over 1957-2016. Figure 7 also shows that the difference between yields and inflation averaged 2.10% over the period, with a standard deviation of 1.35%. Combining these stats with long-term inflationary expectations of 2% suggests that long-term yields may gravitate towards 4.1% in the long-term, and under average conditions. Clearly, yields remain low today, but they are forecasted to increase, although they are expected to do so at a gradual pace over the next few years, and it may take quite some time to reach 4% levels, if they in fact do. The working papers for Figure 6 and Figure 7 are appended as Exhibit E to my evidence.

FIGURE 7

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2016)

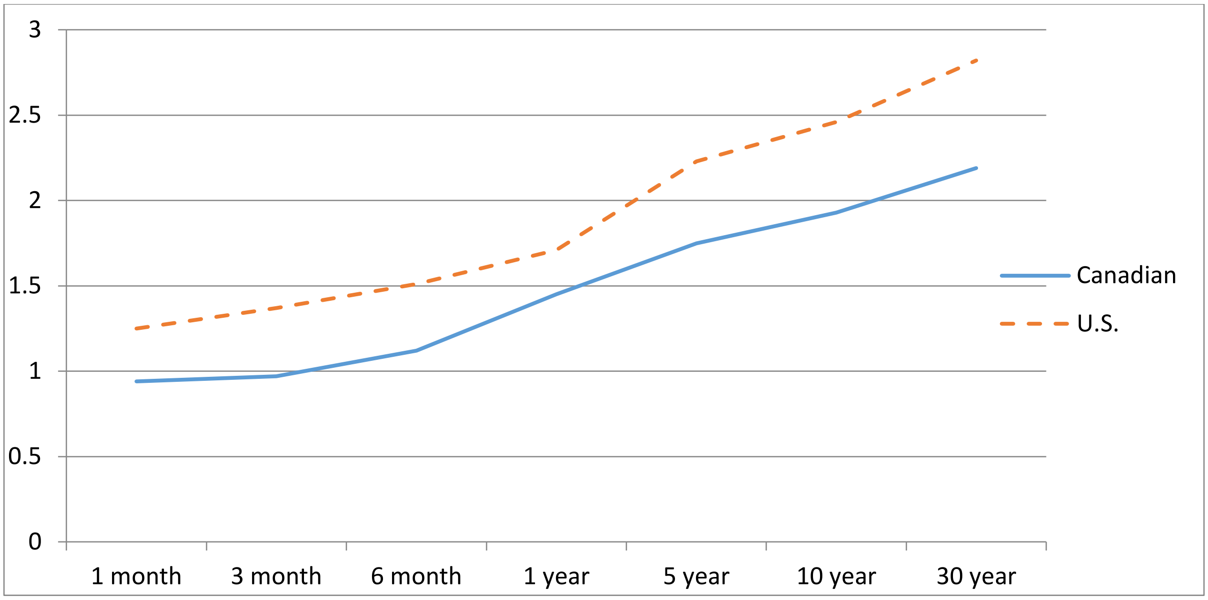


Data Source: CANSIM database.

Figure 8 below depicts the yield curves for Canada and the U.S. as of December 19, 2017. We can see that U.S. rates exceeded Canadian rates across the entire yield curve. For debt that matures within a year, U.S. yields were between 1.2% and 1.7%, while in Canada they were between 0.94% and 1.45%. At the long end of the yield curve, we see 10-year and 30-year U.S. rates of 2.46% and 2.82%, which exceed their Canadian counterparts of 1.93% and 2.19% by 53 bp and 63 bp respectively. According to the 10-year government yield forecasts for Canada and the U.S. from Consensus forecasts (October 2017), the spread between U.S. and Canadian rates are expected to narrow from their current level of 63 bp to 40 bp by October of 2018. The working papers for Figure 8 are appended as Exhibit F to my evidence.

FIGURE 8

YIELD CURVES – CANADA AND THE U.S. (DECEMBER 19, 2017)



Sources: U.S. Data - https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield, December 20, 2017. Canadian data – http://www.pfin.ca/canadianfixedincome/Default.aspx, December 20, 2017.

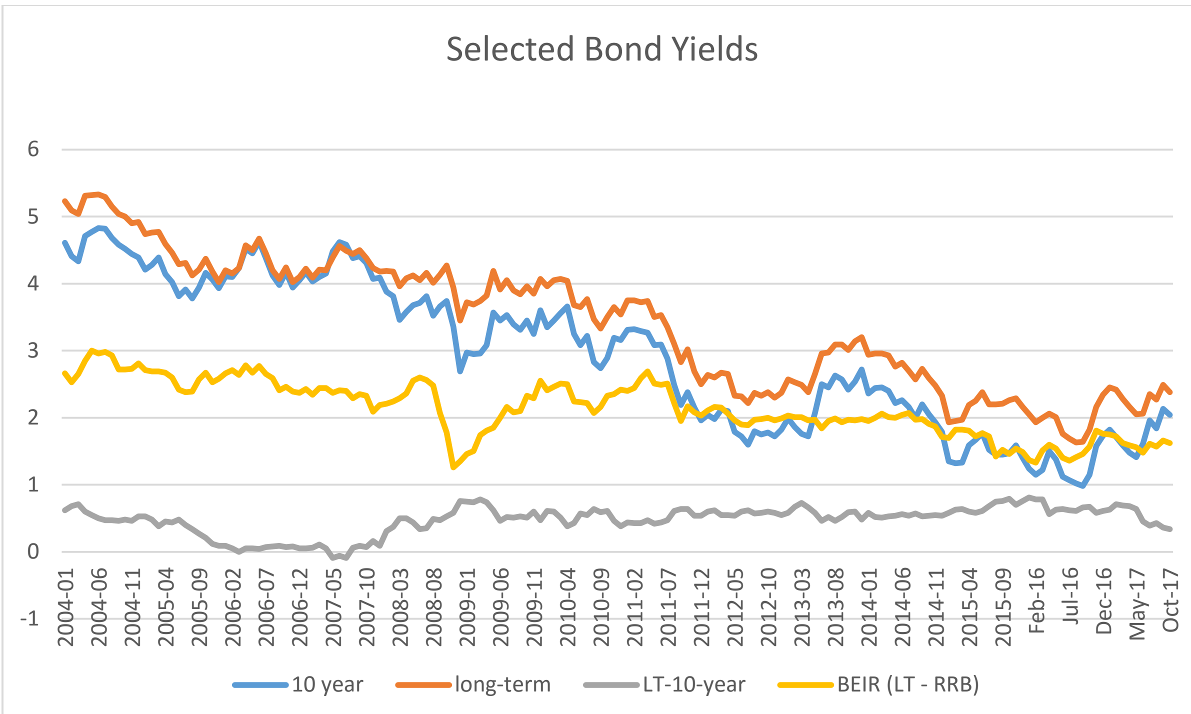
2.3.2. Interest Rate Levels

Figure 9 shows 10-year and long-term bond yields in Canada over the last 14 years, which have moved in tandem for the most part, with a correlation coefficient of 0.99 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.48% (0.53%) over the entire period. It is obvious from Figure 9 that this spread has narrowed considerably during 2017 and sat at 0.34% at the end of October 2017, with long-term rates of 2.38% and 10-year rates of 2.04%, before falling further to 0.26% by December 19, 2017, as long-term rates and 10-year rates fell to 2.19% and 1.93%, respectively, as noted above. Figure 9 also shows the break-even inflation rate ("**BEIR**"), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR is often viewed as an indicator of future inflation rates. This rate remained within the Bank of Canada's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.26% in November of 2008 around the peak of the crisis, and averaging 2.14% overall, slightly above the Bank's target. It sat at 1.62% at the end of October 2016, a mere 8 basis points below the Bank's CPI forecast for

2018, and 28 basis points below the Consensus CPI forecast. The working papers for Figure 9 are appended as Exhibit G to my evidence.

FIGURE 9

SELECTED BOND YIELDS – CANADA (January 2004-October 2017)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Considering the discussion above, it is possible that bond yields will increase, albeit slowly, in the coming months, although this is far from a given fact. For example, this represented the consensus view of most economists as of October 2017, as can be seen in Table 5, which reports Consensus forecasts for Government of Canada 10-year bond yields. In particular, the October 2017 Consensus forecasts for 10-year Canada bond yields were 2.3% for the end of January 2018 and 2.5% for the end of October 2018 – representing significant increases from their October 2017 level of 2.04%. Yet, as of December 19, 2017, the 10-year rate had actually decreased 11 bp to 1.93%, a full 37 bp below the January 2018 forecast.

Despite the consistent inaccuracy of Consensus yield forecasts, if we assume the predicted increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 2.4% for 2018, with a rate of 2.5% at the start of 2019. Assuming that the long-term average 50 bp spread of 30-year yields over 10-year yields persists throughout 2018, this implies long-term rates would increase from the December 19, 2017 level of 2.19% to an average of 2.9% throughout 2018, and would lie at around 3.0% by January of 2019.[10]

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2018)

10-Year Canada Yields	**Jan-18**	**Oct-18**
Conf. Board of Canada	2.2	2.6
CIBC World Markets	2.0	2.2
IHS Economics	2.6	3.3
Citigroup	2.4	2.7
BMO Capital Markets	2.3	2.6
Desjardins	2.4	2.9
Econ Intell Unit	2.1	2.5
Oxford Economics	2.1	2.3
EconoMap	2.3	2.5
JP Morgan	NA	NA
National Bank	2.4	2.8
RBC	2.4	2.9
TD Bank	2.1	2.4
University of Toronto	NA	NA
Scotia Bank	2.2	2.5
Informetrica	2.3	2.5
Inst Fiscal Studies	2.1	2.3
Capital Economics	2.5	2.2
Centre for Spatial Economics	NA	NA
Average	**2.3**	**2.5**
Median	**2.3**	**2.5**
Max	**2.6**	**3.3**
Min	**2.0**	**2.1**

Source: Consensus Economics Inc. (October 2017).

As noted in my evidence in the 2016 GCOC Proceeding, reproduced above, it is reasonable to assume that as economic and capital markets continue to improve that A-rated utility yield

[10] Using the prevailing 26 bp spread between 10-year and 30-year yields as of December 20, 2017, would result in Consensus-based long-term yield estimates of 2.66% for 2018 and 2.76% for the start of 2019.

spreads could continue to decline from their current levels of 1.26% (as of November 15, 2017), which would offset to some extent any expected increases in 10-year (and long-term) government yields. Of course, if some of the *uncertainties* identified earlier persist or get worse, these spreads may not return to normal levels, or may do so much slower than expected, so it is not a given. However, under such circumstances, it is unlikely that government yields would increase as much as expected – so changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent. This is consistent with the observed correlation coefficient of -0.49 between long-term government bond yields and A-rated Utility spreads that was noted previously.

2.3.3. Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 6 reports summary statistics for Canadian capital markets over the 1938 to 2016 period. The working papers for Table 6 are appended as Exhibit H to my evidence.

TABLE 6

CAPITAL MARKET SUMMARY STATISTICS – (1938-2016)

1938-2016 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (CAD)
Average	3.71	11.14	6.54	4.69	12.76
Median	2.82	11.08	4.26	3.86	12.50
Std. Dev.	3.42	16.44	9.05	4.24	17.36
Geo. Mean	3.65	9.88	6.18	4.61	11.40

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM.

The long-term average return in the Canadian stock market over this period was 11.1%, with a geometric mean of 9.9%. This occurred over a period in which inflation averaged 3.7% (geometric mean of 3.65%). This implies "real" returns of approximately 7.4% (6.2%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.2% to 9.4% going forward. These numbers are consistent with, but are higher than, most current estimates of expected stock returns going forward by market professionals, as shown in Table 6 and as discussed in Section 3.1.

2.4. The Alberta Economy

The Conference Board of Canada ("**CB**") 2017 Autumn Provincial Outlook, appended as Exhibit AB to my evidence, estimated that Alberta led the provinces in GDP growth during 2017 at 6.7%. They suggest that this was somewhat surprising and that the strong recovery was driven "largely by rising oil production and a swift turnaround in drilling levels." They also noted the contribution of domestic strength outside the energy sector.

CB does not expect this exceptionally strong growth to continue, but will be followed by more moderate GDP growth rates of 2.1% in 2018 and 1.6% in 2019. The growth will moderate in response to slow growth in energy sector investment and a moderation of the increase in oil production. They do note that recent strength in oil prices may lead to higher than expected drilling rates, which may cause GDP growth to exceed their growth forecasts. So, overall we see a much more optimistic view of the Alberta economy than the one presented during the 2016 GCOC Proceeding.

3. ROE CALCULATIONS

3.1. Capital Asset Pricing Model Estimates

3.1.1. CAPM Overview

This section employs the commonly used CAPM to estimate the allowed ROE for the average regulated Alberta utility. Essentially CAPM can be used to estimate the required ROE (Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

Ke = RF + (ERm – RF) Beta

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of Financial analysts;[11]
- by over 70 percent of U.S. CFOs;[12]
- by close to 40 percent of Canadian CFOs.[13]

Of course, the CFOs and analysts are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous decisions, which is appropriate in my opinion.

A recent study by Berk and van Binsbergen (2017)[14] also provides support for the use of CAPM as the most widely used model by investors, stating:

> We find that investors adjust for risk by using the beta of the capital asset pricing model (CAPM). Extensions to the CAPM perform poorly, implying that investors do not use these models to compute discount rates.[15]

The authors go on further to highlight the fact that this model should be used by practitioners, despite its limitations, quite simply because it is the most widely used model by investors, who in turn drive equity returns:

> We have demonstrated that among a range of proposed models, the CAPM—though perhaps far from being a perfect model of risk—is most consistent with investor behavior. Thus, if the criterion for deciding how to compute the discount rate is to use the method investors use, **practitioners should use the CAPM**.[16]

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[11] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AC.
[12] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AD.
[13] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AE.
[14] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AF.
[15] *Ibid.*, page 25.
[16] *Ibid.*, page 32.

3.1.2. Estimating RF

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate risk-free rate ("**RF**"), since it is virtually guaranteed and does not fluctuate. However, it is common practice to use the CAPM to estimate the required return on common equity over many periods, such as when trying to estimate the cost of a firm's common equity financing component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are more representative of the rate that could be obtained over longer investment horizons. This practice is consistent with previous decisions.

Similar to the approach I used in the 2016 GCOC Proceeding, which worked very well as discussed previously, I estimate RF using the approach used by the Commission in 2013, as described in paragraph 93 of the2013 GCOC Decision. In particular, the October 2017 Consensus forecasts for government 10-year yields are 2.3% for January 2018 and 2.5% for October 2018. Adding the long-term average spread between 10- and 30-year government yields of 50 basis points to these forecasts, implies forecasted 30-year government bond yields of 2.8% and 3.0% respectively. So 3.0% will provide the upper limit of my RF estimate range. I will round up the actual prevailing long-term government yield of 2.19% as of December 19, 2017 to 2.2%, and use it as my lower bound. This gives me a range of 2.2-3.0% for my 2018-19 RF estimate, with a mid-point of **2.6%**.

3.1.3. Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium ("**MRP**"), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 7 below provides useful guidance in determining a reasonable estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into three categories: (1) historical returns; (2) current (i.e., 2017) long-term market forecasts from 10 different sources; and, (3) long-term market forecasts from 6 sources that were included in my evidence in the 2016 GCOC Proceeding, and that are more dated. In the 2016 GCOC Decision, the Commission expressed concern regarding the dated nature of some of my cited sources for expected market returns that I referenced in my evidence in the 2016 GCOC Proceeding. Therefore, I do not explicitly attach any weight to the estimates provided from those 6 sources that I previously referenced. I include these sources in Table 7 to illustrate a point – these estimates are in line with today's forecasts. This is to be expected, since they are *long-term* forecasts, and since *long-term* market prospects have not changed materially over the last 5 years or so.

Despite the objections by the utilities, the Commission noted these forecasts are informative, stating:

> In the 2013 GCOC decision, the Commission confirmed its view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities. The Commission **continues to hold this view** and agrees with Dr. Booth's assessment that **these reports are informative**, since these types of reports are circulated in the investment community, although they may be used for different reasons. Therefore, **the Commission will consider return expectations of finance market professionals in arriving at an allowed ROE value**. The Commission is not indicating a preference for one type of report versus another. The reports and any potential perceived biases in those reports will be evaluated on their merits.[17]

Hence, the Commission believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity is far more relevant than market expectations determined using unrealistic assumptions, such as those provided by the utilities' experts. In other words, market participant beliefs represent an important and practical "benchmark," against which any utility ROE estimate must be compared. Table 7 provides Canadian, U.S. and global evidence; however, since I estimate CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence.

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[17] Decision 20622-D01-2016, 2016 GCOC Decision, page 64, para. 296 [footnotes omitted] [emphasis added].

TABLE 7

HISTORICAL AND FORECAST EQUITY RETURNS

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
HISTORICAL RETURNS				
1. Table 6 (Cleary evidence)	Historical: 1938-2016	Real: 6.2% GA 7.4% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[18]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017. Source: https://www.calpers.ca.gov/docs/board-agendas/201701/day1/3.3-2018-alm_presentation-2-mckinsey.pdf [19]	Historical: 1915-2014		Real: 6.5%	
Average (Range)		**Real: 6.55% (5.6%-7.4%)**	**Real: 7.07% (6.4%-8.3%)**	**Real: 5.15% (4.3%-6.0%)**
FORECAST RETURNS				
4. Financial Planning Standards Council and Institut Quebecois de planification financiere as cited in: "Investors need to be ruthlessly pessimistic about their returns," R. Carrick, Globe and Mail, Report on Business, August 10, 2017, B7.[20]	Long-term forecast	Nominal: 6.5%		
5. "Capital Market Assumptions (as of March 31, 2017)," AON Hewitt.[21] Source: http://www.aon.com/attachments/human-capital-consulting/capital-market-assumptions-2017-q1.pdf	10-year forecast	Nominal: 6.3%	Nominal: 6.5%	
6. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017.[22] Source: https://www.calpers.ca.gov/docs/board-agendas/201701/day1/3.3-2018-alm_presentation-2-mckinsey.pdf	20 year forecast		Real: 4.0 to 6.5% (Adjust by 2% to Nominal: 6.0-8.5%)	

[18] Appended to this evidence as Exhibit AG.
[19] Appended to this evidence at Exhibit AH.
[20] Appended to this evidence as Exhibit AI.
[21] Appended to this evidence as Exhibit AJ.
[22] Appended to this evidence at Exhibit AH.

7. "2017 Long-Term Capital Market Expectations," Franklin and Templeton Investments, February 2017.[23] Source: http://www.franklintempleton.co.uk/downloadsServlet?docid=iyhcbe3v	7-year forecast	Nominal: 8.1%	Nominal: 7.3%	Nominal: Global 7.8% Developed 7.5%
8. "Perspectives: For the Period Beginning April 1, 2017," CIBC Asset Management, March 2017.[24] Source: https://www.cibc.com/ca/asset-management/pdf/news-publications/newsletters/perspectives/perspectives-period-beg-mar2017-en.pdf	10-year forecast	Nominal: 4.0%	Nominal: 1.9%	Nominal: World 3.8%
9. "2017 Long-Term Capital Market Assumptions," J.P. Morgan Asset Management, 2017.[25]	10-15 year forecast		Nominal: 6.25%	
10. "Strategic Perspectives: Capital Market Assumptions and a Toolkit for Asset Allocation," BlackRock, May 2017[26]	10-year forecast	Nominal: 4.3%		Nominal: World excl. Can. 5.8%
11. "Alternative Thinking," AQR Capital Management LLC, First Quarter 2017. [27]	10-year forecast	Real: 3.8% (Adjust by 2% to Nominal: 5.8%)	Real: 4.2% (Adjust by 2% to Nominal: 6.2%)	Real: World (Developed) 4.4% (Adjust by 2.5% to Nominal: 6.9%)
12. "Callan's 2017-2016 Capital Market Projections," Callan Institute, January 2017.[28]	10-year forecast		Nominal: 6.85%	Nominal: World excl. U.S. 7.0%
13. "Long-Term Capital Market Assumptions," Voya Investment Management, February 2017[29]	10-year forecast		Nominal: 7%	
Average (Range)		**Nominal 5.83% (4.3%-8.1%)**	**Nominal 5.28% (1.9%-8.5%)**	**Nominal 6.26% (3.8%-7.8%)**
FORECAST RETURNS (from Evidence in the 2016 GCOC Proceeding)				
14. Financial Planning Standards Council and Institut Quebecois de planification financiere as cited in: "A more realistic take on projected returns," R. Carrick, Globe and Mail, Report on Business, May 23, 2015, B10.[30]	Long-term forecast	Nominal: 6.5%		

[23] Appended to this evidence at Exhibit AK.
[24] Appended to this evidence at Exhibit AL.
[25] Appended to this evidence as Exhibit AM.
[26] Appended to this evidence as Exhibit AN.
[27] Appended to this evidence as Exhibit AO.
[28] Appended to this evidence as Exhibit AP.
[29] Appended to this evidence as Exhibit AQ.
[30] Appended to this evidence as Exhibit AS.

15. "AON Hewitt Capital Market Assumptions & Methodology (Canadian Version)," Aon Hewitt, January 7, 2016.[31]	10-year forecast	Nominal: 8.3% AA 7.1% GA		
16. "Calculating investment returns: Actuarially speaking 6% is a good rule of thumb," Fred Vettese, http://business.financialpost.com/2013/09/21/calculating-investment-returns-actuarially-speaking-6-is-a-good-rule-of-thumb/, January 24, 2014.	Long-term forecast	Real: 5.25% (Adjust by 2% to Nominal: 7.25%)		
17. "Determination of Best Estimate Assumptions for Investment Return (PPICP)," Educational Note, Canadian Institute of Actuaries, Document 212106, December 2012.[32]	Long-term forecast	Nominal: 7%		
18. "Long-Term Returns: A Reality Check for Pension Funds and Retirement Savings," R. Guay and L.A. Jean, Commentary No. 395, C.D. Howe Institute, December 2013.[33]	Long-term forecast	Nominal: 6.9%		
19. "Estimating Equity Returns," Victor Modugno, Sponsored by Society of Actuaries' Pension Section Research Committee, Society of Actuaries, October 2012.[34]	Long-term forecast	Nominal: 6.3%		
Average (Range)		**Nominal 7.18% (6.5%-8.3%)**	**Nominal 6.3%**	

The first three sources in Table 7 provide historical long-term real returns for Canadian, U.S. and global stock returns over three extremely long time periods (i.e., 79 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.55%, with a range of estimates of 5.6% to 7.4%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.55%, ranging from 7.6% to 9.4%, based solely on historical results. The next 10 sources represent 2017 estimated long-term market returns from a number of reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms such as AON Hewitt and McKinsey; and, several investment management firms such as CIBC Asset Management, BlackRock, etc.). Since most of the estimates are provided in nominal terms, I adjust those made in real terms to corresponding nominal terms by adding 2% expected inflation. The Canadian market nominal estimates range from 4.0% to 8.1%, and average 5.83%. Deducting the 2% expected

[31] An excerpt is appended to this evidence as Exhibit AZ.
[32] Appended to this evidence as Exhibit AU.
[33] Appended to this evidence as Exhibit AV.
[34] Appended to this evidence as Exhibit AW.

inflation, this translates to an average *real* return of 3.83%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.4% range over the next 5-10 years, with most of them citing the current low interest rate environment as one of the main contributing factors.

I believe that both historical returns and current expectations of market professionals represent the <u>best</u> sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above, suggests a range of estimates in the 4.0% to 9.4% range. In my evidence in the 2016 GCOC Proceeding, I suggested a range of 7-9% made sense, and that a mid-point of 8% seemed like a reasonable best estimate. Having gathered much more information regarding market professionals' opinions for the purposes of the current proceeding, as well as having conducted numerous subsequent conversations with finance professionals on the topic, I am now convinced that 8% is in fact a somewhat optimistic estimate; although possible. As a result, I now believe that a more appropriate range for expected long-term Canadian stock market returns is 6-9%, and the mid-point of 7.5% represents a better point estimate. Not coincidentally, it is also consistent with my choice of MRP of 5%, discussed below, and my RF estimate of 2.6%, as discussed above.

There was much discussion during the 2016 GCOC Proceeding regarding the informativeness of the beliefs or forecasts of market professionals. Not surprisingly, the utilities' experts argued then, as they do now, that such beliefs are not relevant, just as they similarly implicitly ignored the historical evidence regarding long-term real returns earned in the stock markets. This is because both historical evidence and the beliefs of market professionals provide overwhelming evidence that contradicts the utilities' experts' expected market return estimates. For example, in the current proceeding, the expected Canadian stock market return forecasts provided by the utilities' experts fall within the range of 12.7% to 15.6%.[35] These estimates indicate real returns that are somewhere between 14%-79% higher

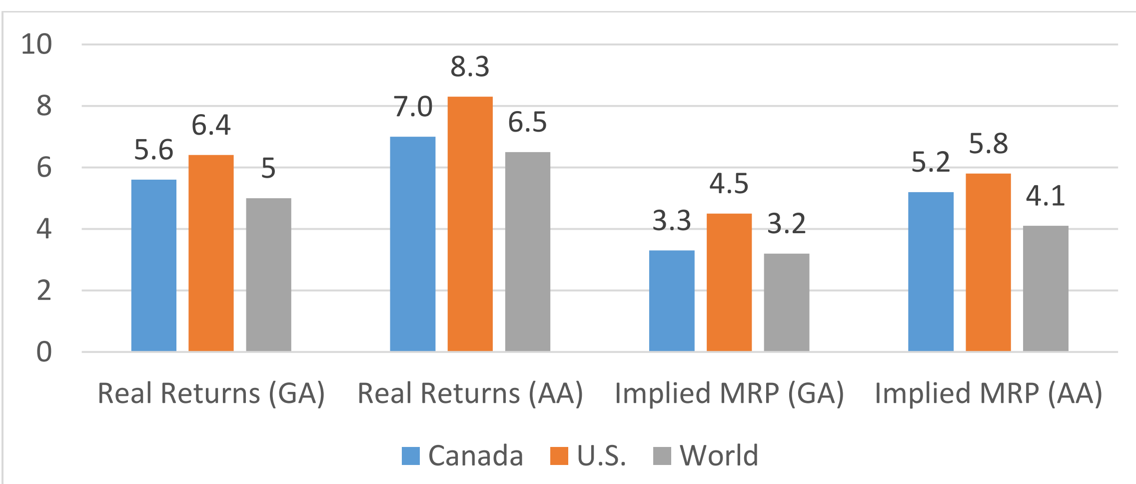
[35] These figures are based in large part upon MRP estimates derived for a market index (i.e., S&P/TSX Index or S&P 500 Index) that are determined using the single-stage dividend discount model (DDM) combined with analyst estimates that exceed expected nominal GDP growth. Hence, the constant growth rates employed by the violate one of the conditions used by the Commission in previous decisions to reject such single stage DDM estimates. I will discuss this flawed approach to estimating MRPs in greater detail later in my evidence.

than average long-term real returns between 5.6%-7.4%. The nominal estimates noted above are even more out of touch with current expectations of market participants, being 57%-263% above current finance professionals' forecasts of Canadian long-term stock market returns reported in Table 7, which ranged from 4.3% to 8.1%. In my view, these are unrealistically high market forecasts which do not reflect the views of finance practitioners.

Figure 10 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. (5.8% and 4.5%) and Canadian (5.2% and 3.3%) figures over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for stock and bond returns over the 1957 to 2016 period, which were 4.6% (3.7%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 11.

FIGURE 10

CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)

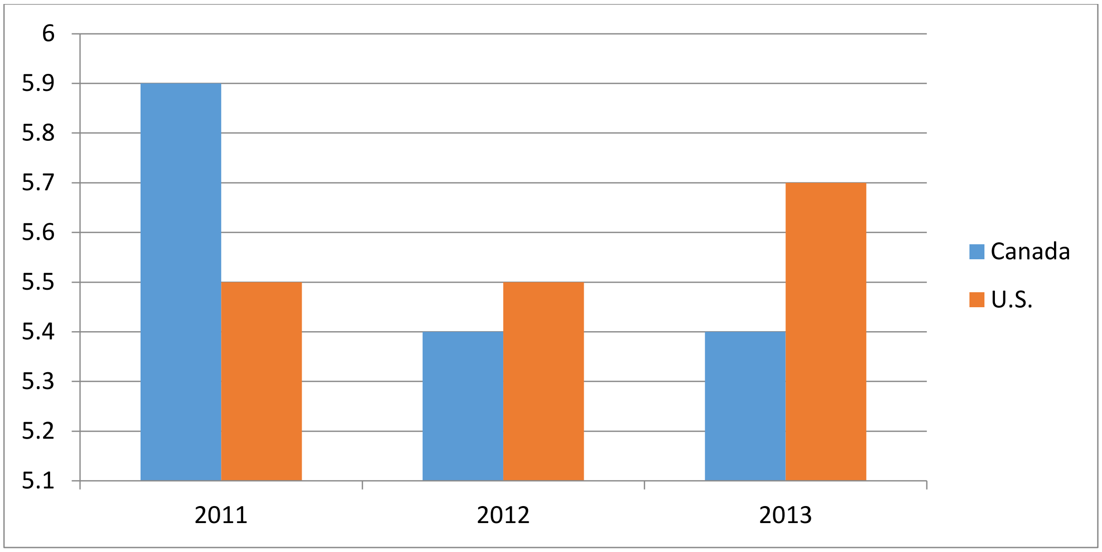


Source: Dimson, E., Marsh, P. and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[36]

[36] Appended as Exhibit AG.

FIGURE 11

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2011-2013)



Source: "Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers," 2013, by Pablo Fernandez, Javier Aguirreamalloa, and Pablo Linares, Working Paper, IESE Business School.[37]

Based on the previous discussion of capital markets, I concluded that stock markets reflect fairly normal conditions, but are experiencing below average volatility, which is lower than at the time of the oral hearings in both the 2016 GCOC Proceeding and the 2013 GCOC Proceeding. Therefore, I use an **MRP of 5%**, which is the mid-point of the commonly used 4-6% range, 20 bp below the long-term average Canadian MRP of 5.2%, and 170 bp above the long-term geometric mean MRP of 3.3%. This seems appropriate in today's environment, where economic and market conditions are fairly normal in terms of valuation metrics like P/E ratios and dividend yield measures, but market volatility is below average. This is consistent with the practice of using 6%when market uncertainty is above average, using 5%when markets are normal, and using 4% during periods of extreme market and economic optimism. These estimates are also consistent with previous decisions by the AUC. For

[37] Appended as Exhibit AT.

example, the AUC used an MRP range of 5-7% in the 2013 GCOC Decision[38] and 5.0-7.25% in Decision 2011-474 (the "**2011 GCOC Decision**").[39].

I know from having read numerous investment reports and from having seen numerous presentations from finance professionals that it is common practice to use a range of 3-7% for the MRP when using the CAPM to estimate required returns of equity for firms, with the large majority of MRP estimates falling in the 4-6% range. In fact, it is so common, that it is almost assumed.. Similarly, it has also always been the case that the MRP would be adjusted upwards during higher periods of uncertainty, and downwards during periods of less uncertainty. I provide some strong evidence below regarding MRPs which is included in two research articles written by prominent finance professors.

In a 2013 working paper, Aswath Damodaran discusses MRP estimation (which he refers to as the equity risk premium (ERP)).[40] In this paper, Dr. Damodaran discusses the results of Merrill Lynch from its monthly surveys of global institutional investors evidence:

> Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update.[41]

This evidence verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, the 3-4.5% range), and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

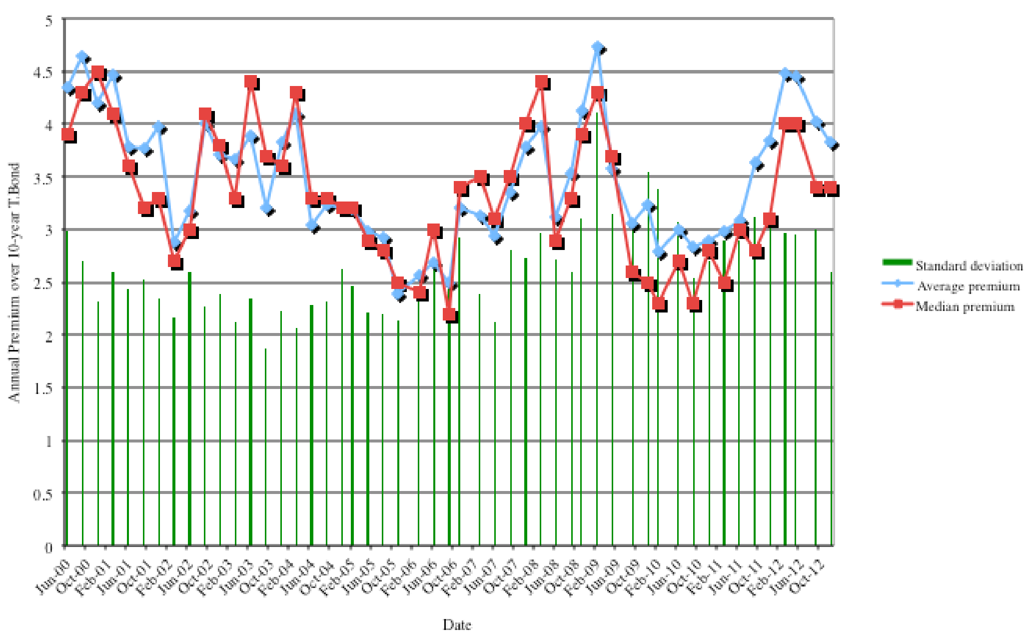
Dr. Damodaran then proceeds to discuss the results of Graham and Harvey (2013)'s surveys

[38] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 115.
[39] Decision 2011-474, 2011 Generic Cost of Capital, para. 59.
[40] Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition," Aswath Damodaran, Stern School of Business, New York University. This article is appended as Exhibit AX to this evidence.
[41] *Ibid.,* pages 18-19.

of CFOs regarding MRPs:

> To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.

Figure 2: CFO Survey Premiums



> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[42]

This evidence also verifies that finance professionals believe that MRPs lie within the 3-6% range (or , more aptly, in the 2.47-4.74% range) over the 2000-2012 period, and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran also discusses the implied MRPs in the S&P 500 Index from 1960-2012 and produces Figure 9, below:[43]

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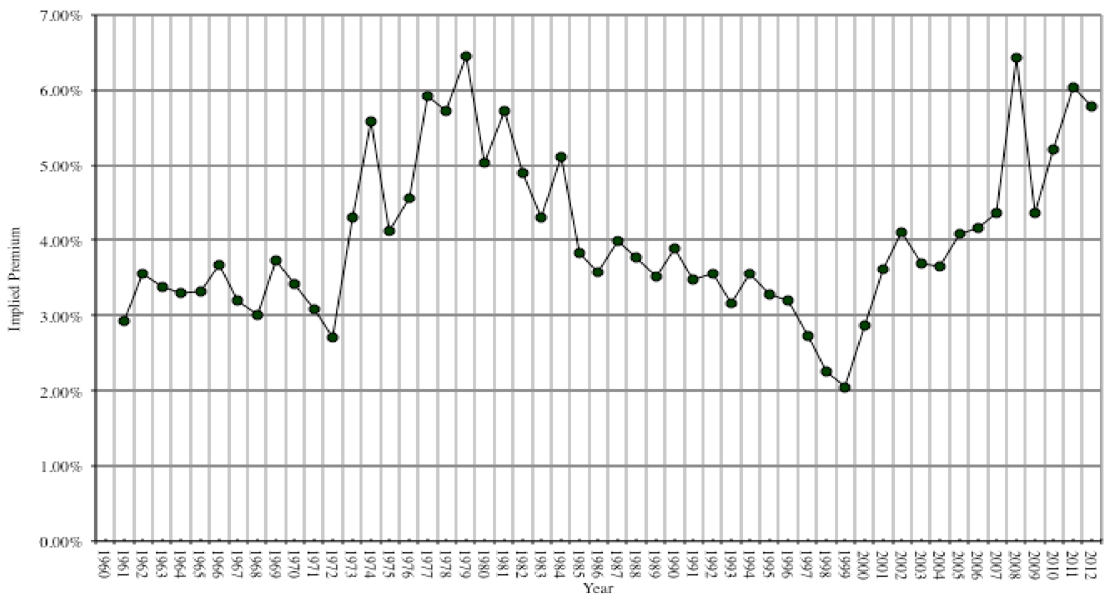
[42] *Ibid.*, pages 20-21.
[43] *Ibid.*, page 74.

Figure 9: Implied Premium for US Equity Market



This evidence also shows that implied MRPs generally lie within the 3-6% range (and in fact are never less than 2% or above 6.5%), and that the MRP increases during periods of uncertainty (e.g., 1979 and 2008), and declines during periods of less uncertainty (e.g., the boom in stock markets at the end of the 1990s).

Dr. Damodaran discusses his own approach to estimating and using MRPs when valuing companies, stating:

> On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5% equity risk premium for mature markets in 2010. With the increase in implied

> premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2013, I will be using a slightly lower equity risk premium (5.80%), reflecting the drop from 2012.[44]

This evidence verifies that a well-respected finance professional, textbook author, and provider of financial data uses MRPs in the 4-6% range and varies his choice of MRP so that it increases during periods of uncertainty, and declines during periods of less uncertainty.

The results of a 2013 survey by Graham and Harvey was discussed above by Dr. Damodaran.[45] I would also note the following conclusions Dr. Graham and Dr. Harvey reached based on their ongoing surveys of CFOs:

> the CFOs believe that the "risk premium" is a longer-term measure of expected excess returns and best covered by our question on the expected excess return over the next ten years – rather than the one-year question. Three-fourths of the interviewees use a form of the Capital Asset Pricing Model (which is consistent with the evidence in Graham and Harvey, 2001). They use a measure of the risk premium in their implementation of the CAPM.[46]

These conclusions are consistent with the long-term (with adjustments) approach to estimating the MRP that I advocate. It also shows that 3/4ths of CFOs use some version of the CAPM.

Further, Dr. Graham and Dr. Harvey examine the relationship between MRPs and two other common measures of risk aversion that I have referenced previously – the VIX and yield spreads:

> Finally, we consider two measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.52. If the closing day of the survey is used, the correlation is roughly the

[44] *Ibid.*, page 79.
[45] "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. This survey is appended to this evidence as Exhibit AY.
[46] *Ibid.*, page 8.

> same. Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.
>
> We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.54.[47]

This evidence confirms that MRPs tend to increase as risk aversion increases, and decrease as risk aversion declines, which is consistent with my approach to estimating MRPs.

In sharp contrast to the approach that I use in determining a reasonable MRP, and contrary to historical evidence, as well as the estimates provided by market professionals, the utilities' experts arrive at Canadian MRP estimates of 8% (Villadsen), 9.38% (Coyne) and 11.90-12.53% (Hevert). All of these estimates are unrealistic and far exceed the upper bound suggested by historical evidence and those estimated by the finance community. When combined with their inflated estimates of RF (3.3% - Villadsen; 3.26% - Coyne; and, 2.38%-3.08% - Hevert), they obtain expected Canadian equity market returns of 11.3%, 11.76% and 13.18%-14.71% respectively. As I demonstrate, all of these estimates are unrealistic.

Mr. Hevert and Mr. Coyne both estimate their MRPs using single-stage Dividend Discount Model ("**DDM**") estimates for the S&P/TSX Index based upon analyst estimates of growth rates that far exceed expected GDP growth. This violates the findings of the Commission in terms of allowable growth rates that can be used in the constant-growth version of the DDM.[48] The use of this model across a broad number of firms in different industries and of various sizes and stages of development is faulty to begin with, since it implies that all firms used to estimate the MRP pay dividends that can be expected to grow at a constant annual rate to infinity. The flaw in this approach, particularly for the S&P/TSX Index, is obvious if we note that 34 (Hevert) to 58 (Coyne) of the 250 companies included in the TSX Index did

[47] *Ibid.*, pages 14-15.
[48] Decision 20622-D01-2016, 2016 Generic Cost of Capital Decision, para. 287.

not have a valid dividend yield, which suggests they do not pay dividends. An additional 143 (Hevert) to 149 (Coyne) firms in the TSX Index did not have valid earnings growth estimates available. As a result, Mr. Hevert and Mr. Coyne estimated the MERP for the TSX Index using only 88 and 79 firms respectively. Of far greater concern is the fact that the average *long-term growth rates* used to estimate the Canadian MRPs were unrealistically high at 13.08% (Hevert) and 11.99% (Coyne) – in strong violation of the Commission's requirement that such long-term growth rates should not exceed expected nominal GDP growth of about 4%. This is an attempt to include equity estimates based on unrealistically high, and inadmissible, growth rates. In addition, the MRPs are estimated using the *actual* prevailing long-term government bond yields; however, the experts then proceed to use these unrealistic MRPs in combination with measures of RF that are based on *expectations* of forecasted higher bond yields, rather than using today's yield – which further inflates their CAPM estimates. Clearly, these MRP estimates should be disregarded, since they are uninformative.

Dr. Villadsen uses estimates that she claims are provided by Bloomberg that indicate a Canadian MRP of just below 10%, which she combines with her Bloomberg U.S. MRP estimate of 7.3% to arrive at a Canadian MRP estimate of 8%. In response to Villadsen-UCA-2017NOV21-007,[49] Dr. Villadsen simply provided screenshots from Bloomberg, which fail to provide sufficient detail to determine precisely how Bloomberg estimates these MRPs. However, what is provided suggests that the Bloomberg estimates are based on the constant-growth version of the DDM which uses analyst growth estimates as the perpetual long-term growth rate. Therefore, in all likelihood, these MRP estimates suffer from the same limitations as those of Mr. Hevert and Mr. Coyne. As a result, these MRP estimates are also not meaningful.

3.1.4. Estimating Beta

We now require a beta estimate to apply the CAPM. Appendix B includes my recommendations to the Commission that will avoid the issue of having to consider such a wide range of expert beta estimates, such that the range provides little guidance. Appendix B

[49] Exhibit 22570-X0428, Information Response to UCA-2017NOV21-007.

provides an examination of historical evidence provided by three of the utilities' experts that confirm the following three points:

1. Canadian utility beta estimates over the last 22-25 years have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate.
2. Canadian utility beta estimates have never come close to one, with maximum values in the 0.6-0.8 range. Neither have U.S. utility beta estimates ever come close to one for that matter. Hence the use of traditional adjusted betas is totally inappropriate.
3. U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered.[50] This is consistent with the higher level of business risk associated with U.S. utilities.

Based on these observations, I made the following recommendations to the Commission in terms of determining reasonable beta estimates:

1. Ensure beta estimates are from reasonable comparators – i.e., exclude U.S. utility beta estimates.[51]
2. If there is a desire or need for "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35 rather than toward 1.0, as is done with published betas provided by services such as

[50] For example, Appendix B shows that Mr. Hevert's historical average Canadian beta estimates of 0.34 (monthly) and 0.38 (weekly) are just over half their U.S. counterpart estimates of 0.61 (monthly) and 0.72 (weekly), after accounting for leverage differences. The implied "unlevered" U.S. betas (0.234 monthly; 0.278 weekly) are almost double those for the Canadian utilities (0.131 monthly; 0.140 weekly). The utilities' experts' approach to estimating betas for Alberta utilities by using U.S. betas is centrally flawed, since they are too high to begin with, and hence not good comparables (i.e., as evidenced by their much high unlevered betas). They attempt to further compound this flawed approach by then determining unlevered betas for U.S. utilities using U.S. D/E ratios, which they then "relever" using higher Canadian D/E ratios. This approach ignores the fact that the unlevered betas are higher for U.S. utilities because they are not good comparators – because they have higher business risk.

[51] It is also obvious that Dr. Villadsen's U.S. pipeline company sample is clearly **not** a reasonable comparable group, with an average beta of 1.04, and with four of the six pipelines being rated BBB- and the other two being rated BBB+. This point was acknowledged by Mr. Coyne in response Coyne-UCA-2017NOV21-003a) when he stated: "Though electric and gas distributors are subject to some competitive risks, the severity of this risk is not comparable to the pipe-on-pipe competition and potential for stranded assets that occurs in the gas transportation pipeline sector."

Bloomberg and Value Line. I illustrate how to implement this approach in Appendix B.

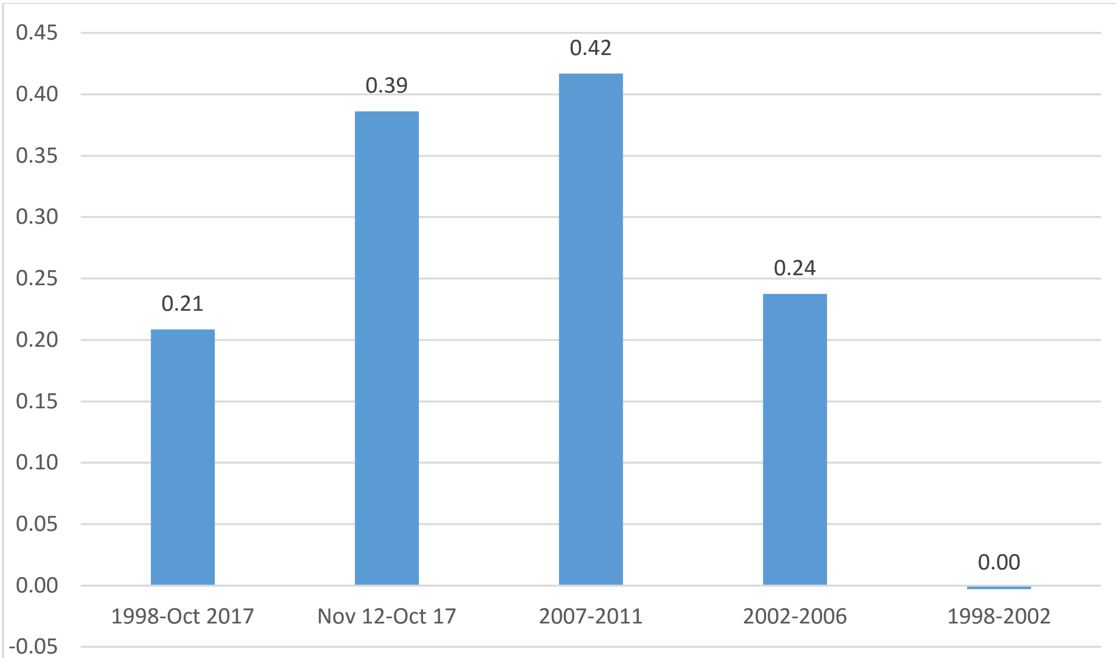
3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

As noted above, a review of the utilities' experts' evidence shows that Canadian utility beta estimates over the last 22-25 years have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate. Such evidence is consistent with my previous empirical estimates, but suggest that the 0.45 beta estimate I used in the 2013 and 2016 GCOC Proceeding is a little on the high side; however, it does represent the mid-point of the range of reasonable beta estimates that I have recommended to the Commission.

Figure 12 reports the average betas calculated using monthly total return data for the TSX Utilities Index over the 1998 to October 2017 period. The first reported beta estimate uses data for the entire 20-year period and is 0.21. The remaining beta estimates are for five-year periods, which is a commonly used time horizon for estimating betas with monthly data. The graph shows that the beta estimate for utilities was approximately 0 over the 1998 to 2002 period, which is one in which the betas for many industries, including utilities, were not meaningful due to the high technology boom and bust during that period. During 2002-06 the beta estimate was 0.24, then 0.42 during 2007-12, and finally is 0.39 for the most recent five-year period ending October 2017. This most recent five-year beta estimate of 0.39 is very much in line with the long-term average of 0.35 and the estimate of 0.45 that I used in the 2013 and 2016 GCOC Proceedings. The working papers for Figure 12 are appended as Exhibit I to my evidence.

FIGURE 12

BETA ESTIMATES FOR THE CANADIAN UTILITY INDEX (1998-Oct. 2017)



Data Source: CHASS database.

Table 8 provides beta estimates for several Canadian utilities as of November 2017, based on 60 months of returns. The average is 0.43, slightly above the 0.39 Utilities Index estimate over the November 2012-October 2017 period provided in Figure 12. The average increases slightly to 0.47 if we eliminate TransAlta and Northland, which are primarily non-regulated utilities. If we also exclude Canadian Utilities Ltd. and ATCO, which are holding companies that include interests in non-regulated assets, and we also exclude Algonquin, which also has a mix of regulated and non-regulated assets, then the average declines to 0.37.

TABLE 8

BETA ESTIMATES – NOVEMBER 2017

Firm	Beta
Fortis	0.41
Emera	0.20
TransAlta	NA
Northland Power	0.16
Algonquin Power	0.33
ATCO	0.99
Cdn Utilities Ltd.	0.48
Enbridge	0.59
TransCda	0.26
Average	0.43
Average excl. TransAlta and Northland	0.47
Average (Fortis, Emera, Enbridge, TransCda)	0.37

Source: Bloomberg, November 2017.

Based on the evidence in Figure 12 and Table 8, and combining it with long-term historical averages, a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. The current estimates I provide in Figure 12 and Table 8 average 0.40; however, in order to be consistent with my recommendations in the 2013 and 2016 GCOC Proceedings, I will use the mid-point figure of my recommended range (i.e., 0.30-0.60) of 0.45 as my best point estimate, which is slightly above the long-term average of around 0.35.

3.1.5. Final CAPM Estimates

Government bond yields remain low by historical standards, and A-rated Canadian utility bond yield spreads were sitting at 126 bp in November of 2017, much lower than the 200 bp observed in February of 2016, but still slightly above the long-term average spread of 100 bp. While this spread is quite small, I will adjust for it as I have in previous proceedings. Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian Utilities.[52] Consistent with this research, I will add half of the "above average" yield spread, or 0.13%, to my CAPM estimate to account for this time varying risk premium.

[52] Refer to: A. Garcia and J. Yang, "Understanding Corporate Bond Spreads Using Credit Default Swaps," Bank of Canada Review, Autumn 2009. This article is appended as Exhibit AR to this evidence.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous Commission decisions, and is consistent with long-term estimates. Combining these items we get a range of CAPM estimates for the required equity return for the average regulated Alberta utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests that 5.5% is a reasonable ROE (in the 4.05% to 6.93% range).

TABLE 9

CAPM ESTIMATES – 2018-2019

Estimate	RF (%)	MRP (%)	Beta	Spread Adjust. (%)	Financial Flex. (%)	Ke (%)
Max	3.0	5.5	0.60	0.13	0.50	6.93%
Min	2.2	4.5	0.30	0.00	0.50	4.05%
Best Estimate	2.6	5.0	0.45	0.13	0.50	**5.49%**

The CAPM parameters used (i.e., RF of 2.6%, MRP of 5% and the spread adjustment of 0.13%) imply a required return on the entire market of 7.73%, which is in line with, but at the high end of, the long-term market return expectations of finance professionals provided in Table 7, and is also in line with the long-term real returns on Canadian stocks. It is also very close to my best estimate of 7.5% for the long-term expected return on the market that I discussed previously. The **5.5%** estimate for the utilities is 50 bp below my CAPM estimate in the 2016 GCOC Proceeding despite the fact that I use the same beta estimate of 0.45, and that my RF estimate is actually 0.30% higher at 2.6% than it was in 2016. This is because the spread adjustment declined 0.37% (i.e., from 0.50% to 0.13%) which reflects lower yield spreads paid by Canadian utilities. Relatedly, the other contributing factor to my lower CAPM estimate is the use of an MRP of 5% to represent a normal risk market, versus the 6% MRP that I used in 2016 to reflect higher levels of risk aversion in the market as evidenced by elevated yield spreads and VIX levels. As discussed previously, all indications suggest risk aversion levels are now normal. Multiplying this 1% decrease in the MRP by the beta of 0.45 implies that this choice drove my CAPM estimate down by 0.45%.

3.1.6. Utilities' Experts' CAPM Estimates

Finally, it is instructive to compare my CAPM estimates with those that would have been provided by the utilities' experts if they used more reasonable assumptions for RF and MRP, and did not use adjusted betas or U.S. evidence. These estimates (for their Canadian utility samples) are provided in Table 10, with reference to the associated information response . They are based on an MRP of 4.25% (slightly below the 5% I used), and on the use of raw betas rather than adjusted betas. They range from 5.32% to 6.41%, with an average of 5.9%, which is reasonably close to my estimate of 5.5%, unlike the much higher CAPM estimates the utilities' experts obtain when they use inflated (i.e., adjusted) betas and MRP estimates.

TABLE 10

ADJUSTED CAPM ESTIMATES OF UTILITIES' EXPERTS

Expert	**Information Response**	**New Assumptions**	**CAPM Estimate**
Dr. Villadsen	Exhibit 22570-X0428, Villadsen-UCA-2017NOV21-015(b)	Use "raw" (unadjusted) betas / RF = 2.3% / MRP = 4.25% /	5.6% - adjust by 50 bp for financing charges to get 6.1%
Mr. Hevert	Exhibit 22570-X0496, Hevert-UCA-2017NOV21-033(b) Exhibit 22570-X0507, HEVERT-UCA-2017NOV21-033 Attachment	Use "raw" (unadjusted) betas / MRP = 4.25% /	4.82% (2017) to 5.52% (2018) - adjust by 50 bp for financing charges to get 5.32% (2017) and 6.02% (2018)
Mr. Coyne	Exhibit 22570-X0310, Coyne-UCA-2017NOV21-013 b) Exhibit 22570-X0325, Coyne-UCA-2017NOV21-013 b) Attachment 1	Use "raw" (unadjusted) betas / MRP = 4.25% /	6.41%
AVERAGE			**5.9%**

I have argued and provided supporting evidence in Section 3.1.4 and in Appendix B that it is inappropriate to use adjusted betas for regulated utilities with betas that do not approach, let alone average, 1 over the long term. Using the Empirical CAPM ("ECAPM") also implicitly adjusts the beta used in traditional CAPM estimates. Hence, the ECAPM should also not be used. Using both adjusted betas and the ECAPM together, as is done by Dr. Villadsen and Mr. Hevert, is clearly wrong and, in my view, should never be allowed.[53] The combination of the two approaches essentially adjusts raw betas up twice, and the impact of this is greater the

[53] I note that Dr. Villadsen and Mr. Hevert use different versions of the ECAPM, as illustrated in Table 11.

larger the MRP estimate that is used. I illustrate both of these facts in the top part of Table 11 using the estimates provided by Dr. Villadsen and Mr. Hevert that are reported in Table 10, and then in the bottom part of Table 11 using their individual MRP estimates of 8% and 13.1% respectively.

TABLE 11

ADJUSTED BETA AND ECAPM ESTIMATES

	Dr. Villadsen's ECAPM: K = RF + Beta(MRP) + 1.5(1 – Beta)			**Mr. Hevert's ECAPM: K = RF + 1/4×(MRP) + 3/4×Beta×(MRP)**		
Model	**RF = 2.3%; B (raw) = 0.77; MRP = 4.25%**			**RF = 2.3%; B (raw) = 0.77; MRP = 4.25%**		
	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM
CAPM with raw beta	5.573	---	0.77	4.81	---	0.575
CAPM with adj. beta	5.913	+0.340	0.85[54]	5.41	+0.60	0.716
ECAPM with raw beta	5.918	+0.345	**0.851**[55]	5.26	+0.45	**0.680**
ECAPM with adj. beta	6.138	+0.565	**0.903**	5.71	+0.90	**0.786**
	RF = 2.3%; B (raw) = 0.77; MRP = 8%			**RF = 2.3%; B (raw) = 0.77; MRP = 13.1%**		
	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM
CAPM with raw beta	8.460	---	0.77	9.90	---	0.575
CAPM with adj. beta	9.100	+0.64	0.85	11.75	+1.85	0.716
ECAPM with raw beta	8.805	+0.346	**0.814**	11.29	+1.39	**0.681**
ECAPM with adj. beta	9.325	+0.865	**0.878**	12.68	+2.78	**0.787**

Table 11 illustrates three important facts:

1. using either Dr. Villadsen's or Mr. Hevert's version of the ECAPM results in an implied higher beta if applied to the traditional CAPM (i.e., the one that is most widely used by analysts, CFOs, and investors – as discussed in Section 3.1.1);

[54] Calculated using the Adjusted Beta formula, so that Beta (adj) = 1/3 + 2/3(0.77) = 0.85.
[55] Calculated based on K = 5.918% in traditional CAPM, so Beta = (5.918 – 2.3)/(4.25) = 0.851.

2. using adjusted betas and the ECAPM accentuates the inappropriate upward adjustment of raw betas by doing it twice. This leads to large increases in cost of equity estimates versus those determined using the traditional CAPM; and,
3. the impact of these inappropriate upward beta adjustments is greater for larger MRP estimates, such as the inflated MRP estimates used by the utilities' experts.

These points confirm that the combination of using adjusted betas and ECAPM is not appropriate and should not be permitted, especially in combination with unrealistically high MRP estimates.

3.2. Discounted Cash Flow Estimates

3.2.1. DCF Model Overview

The Commission has appropriately taken DCF estimates into account in making previous decisions as to the appropriate ROE. I use two approaches and apply the DCF model as at the end of 2017 to:

1. find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the "average" company in the market; and,
2. apply the models at the industry level using numbers that are representative of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The DDM is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely. The constant-growth model can be represented as:

$$Price = D_0(1 + g) / (Ke – g) = D_1/(Ke – g)$$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/Price)\times(1 + g) + g$$

3.2.2. Market DCF Estimates

Table 1 showed that real GDP growth averaged 3.2% over the 1962 to 2016 period. This provides one potential estimate of long-term growth that could be used in the single-stage model, since we would expect long-term growth for the overall market to gravitate towards this figure. This assumption is commonly made by financial analysts. Table 1 also showed that average real GDP growth has been lower at 2.5% since 1992, and we could also use this as a long-term growth estimate. Finally, the October 2017 Consensus forecasts suggested real GDP growth for Canada of 1.8% over the 2023-2027 period, with similar growth rates during 2018-2020, so this provides another reasonable estimate of future Canadian economic growth. Of course, we are trying to estimate a "nominal" required rate of returns, so we should use nominal GDP growth as "g." We can estimate nominal growth rates by applying the 2% Bank of Canada inflation target, which is also the average expected inflation rate over the 2023-2027 period according to the October 2017 Consensus forecasts. Doing so, we get the following long-term nominal Canadian GDP growth rate estimates that correspond to the three real growth rates noted above: 5.26%; 4.55%; and, 3.84% - where 4.55% represents the average and mid-point of these three figures. These growth rates are in line with those used by security analysts when they use single-stage growth models to value securities (i.e., they usually use numbers in the 3-5% range *when* they use single period models).

The dividend yield for the S&P/TSX Composite Index as of November 24, 2017 was 2.7%. This is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent 12-month period. Substituting the maximum, minimum and average nominal GDP growth estimates noted above into the single-stage DDM equation provided above, we get the following estimates for the implied equity return for the market as a whole for 2018:

Max: Ke = (D0/Price)×(1 + g) + g = (0.027)×(1.0526) + .0526 = 0.0810 or 8.10%

Average: Ke = (0.027)×(1.0455) + .0455 = 0.0737 or **7.37%**

Min: Ke = (0.027)×(1.0384) + .0384 = 0.0664 or 6.64%

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, these seem to be reasonable estimates. The average of 7.37% is consistent with my long-term forecast for expected market returns of 7.5%, and all three estimates are in line with market forecasts of expected future returns that were provided in Table 7 and that were discussed earlier. The average estimate of 7.37% is also very close to my CAPM market estimate of 7.7% (discussed in Section 3.1.5).

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

I consider the Consensus GDP Growth forecasts that translated into a 3.84% nominal GDP growth rate as my short-term growth rate (g_S), and use the long-term GDP nominal growth rate estimate of 5.26% as the long-term growth rate (g_L). Assuming it takes four years to get back to this long-term expected growth rate, then we would use H = 2, which provides an estimate for Ke of 8.03%. If we assume that this return to long-term growth takes longer (say

8 years), then H = 4, and we get an estimate for Ke of 7.95%. The mid-point of these two estimates is 7.99%, which I round up to 8% for simplicity.

Combining the results from the two DDM models, we get estimates for Ke for the market in the 6.6-8.1% range. I will use the average estimate of 7.4% from the single-stage DDM and 8.0% using the H-model to arrive at 7.7% as my best estimate of the implied return on the market using DCF models. This number is reasonable, very close to my estimate for future market returns of 7.5% discussed in Section 3.1.3, and in line with the expectations of finance professionals and with historical real stock returns. It is also exactly the same as my CAPM estimate for the entire market that was provided earlier. DCF models will work better in aggregate than for Canadian utilities, which leaves us with the issue of how to adjust these figures into a reasonable implied return for utilities that possess considerably less risk than the average company in the market. At minimum, we could say that the market DCF estimates (similar to my CAPM market estimate) suggest that utility returns should be lower than 7.7%.

3.2.3. Alberta Utility DCF Estimates

I will now apply both of the DCF models discussed above to Canadian utilities. Of course, determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's **sustainable growth rate,** which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the ROE, as shown below:

$$g = (1 - \text{payout ratio}) \times \text{ROE}.$$

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures that are generally close to allowed ROEs, which do not usually fluctuate by large amounts.

Table 12 below includes summary statistics on dividend yield, payout ratios and ROE for the 9 Canadian utility firms included in Table 8. This data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using our two DCF models. Panel A reports the average, median, maximum and minimum figures for all 9 utilities for the November 2017 dividend yield ("**DY**"), the average 5-year DY, the 2016 payout ratios and ROEs, and the 2007-16 averages for payout and ROE.[56] Panel B reports the same statistics after eliminating TransAlta and Northland, and Panel C after also eliminating ATCO, Canadian Utilities, and Algonquin. The working papers for Table 12 are appended to my evidence as Exhibit J.

[56] Payout ratios were "capped" at 100% to control the influence of extreme payouts on "averages" - this process obviously had no effect on the reported medians.

TABLE 12

DCF INPUT ESTIMATES – 2007-2016 FIGURES

	DY (Nov 17)	5-year Avg DY	2016 Payout	Avg Payout (07-16)	2016 ROE	Avg ROE (07-16)
Panel A						
Average	3.89	4.26	86.26	72.40	8.16	8.77
Median	4.00	3.80	85.40	72.45	7.03	9.16
Max	4.90	8.00	100.00	100.00	15.69	12.58
Min	2.20	2.10	53.00	59.14	0.72	3.29
Panel B						
Average (excl TransAlta and Northland)	4.03	3.46	83.97	66.00	7.58	10.50
Median	4.00	3.70	85.30	69.28	7.03	11.10
Max	4.90	4.40	100.00	83.97	13.40	14.33
Min	2.90	2.10	53.00	47.47	0.72	4.63
Panel C						
Average (Fortis, Emera, Enbridge, TransCda)	4.28	3.68	88.53	75.17	6.12	10.10
Median	4.30	3.75	85.40	77.69	5.18	10.93
Max	4.90	4.10	100.00	88.53	13.40	13.50
Min	3.60	3.10	80.20	58.93	0.72	3.55

Data Source: Morningstar at www.morningstar.ca.

The summary statistics included above appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. Payout ratios between 66% and 88%, and gravitating toward an average of 66-75%, are in line with historical figures and also with the high dividend paying nature of such profitable, slow growing firms. Similarly, dividend yields in the 3.5-4.5% range are in line with that of the S&P/TSX Utilities Index. The ROE numbers in the 6-10.5% range are also reasonable.

It is difficult to find "typical" or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 13 provides estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 12. These are calculated using the formula above (i.e., g = (1 – payout) × ROE). Column 2 uses the average and median ROE and payout figures for 2016, while column 3 uses the averages over the 2007 to 2016 period. The median and average growth rates range from 0.70% to 3.57%, with an average (and median) of 1.9%. This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.8-5.3% range.

TABLE 13

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

	Implied g (2016)	**Implied g (07-16)**	**Implied Ke (2016 g and Nov 2017 DY)**	**Implied Ke (07-16 g and 5-year DY)**
Average	1.12	2.42	5.05	6.78
Median	1.03	2.52	5.07	6.42
Average (excl TransAlta and Northland)	1.21	3.57	5.29	7.15
Median	1.03	3.41	5.07	7.24
Average (Fortis, Emera, Enbridge, TransCda)	0.70	2.51	5.01	6.27
Median	0.76	2.44	5.09	6.28
Average of 6 averages g = 1.92%				**Average of 6 averages Ke = 5.93%**
Average of 6 medians g = 1.86%				**Average of 6 medians Ke = 5.86%**

The final two columns in Table 13 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 12). Recall this formula can be represented as follows when we begin with the dividend yield based on dividends over the previous 12 months: $Ke = (D_0/Price)\times(1 + g) + g$. The working papers for Table 13 have been appended to my evidence as Exhibit J.

These estimates range from a low of 5.01% using 2016 implied growth and November 2017 DY average numbers and considering only Fortis, Emera, Enbridge and Trans Canada, to a high of 7.24% using 2007-16 median values after excluding Transalta and Northland. As mentioned, it is difficult to determine which group provides the most representative statistics, so it is useful to determine the average of all these estimates. The average of all 6 Ke estimates determined using averages is 5.93%, while the average of the 6 numbers calculated using the medians is 5.86%. I will assign a best estimate single-stage DDM estimate at the mid-point of 5.9%. This estimate is below the 7.7% DDM estimate for the market, which is reasonable since regulated utilities are considerably less risky than the average company. If we add 50 basis points for flotation costs, we end up with a range of 5.5%-7.7%, with a best estimate of 6.4%.

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the implied growth rates determined using 2016 payout ratios and ROEs, which are reported in column 2 of Table 13. I then denote as g_L the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 13. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 14 below. The working papers for Table 14 are appended to my evidence as Exhibit K.

1 **TABLE 14**

2 **H-MODEL ESTIMATES**

Using all 9 Utilities		
	H=2	**H=1**
Current D0/P0	0.0389	0.0389
gs (current sustainable g)	0.0112	0.0112
gL (long-term sustainable g)	0.0242	0.0242
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0112	0.0112
g1	0.0145	0.0177
g2	0.0177	0.0242
g3	0.0210	0.0242
g4	0.0242	0.0242
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0630**	**0.0635**
Excl TransAlta and Northland		
Current D0/P0	0.0403	0.0403
gs (current sustainable g)	0.0121	0.0121
gL (long-term sustainable g)	0.0357	0.0357
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0121	0.0121
g1	0.0180	0.0239
g2	0.0239	0.0357
g3	0.0298	0.0357
g4	0.0357	0.0357
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0755**	**0.0765**
Fortis, Emera, Enbridge, TransCda		
Current D0/P0	0.0428	0.0428
gs (current sustainable g)	0.0070	0.0070
gL (long-term sustainable g)	0.0251	0.0251
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0070	0.0070
g1	0.0115	0.0160
g2	0.0160	0.0251
g3	0.0206	0.0251

g4	0.0251	0.0251
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0674**	**0.0681**
AVERAGE	**0.0686**	**0.0694**

The Ke estimates lie within the range of 6.3% to 7.7%. The average estimate is 6.86% if we assume a 4-year transition in growth rates (i.e., H =2), and is slightly higher at 6.94% if we assume a 2-year transition. Combining these results with a 0.50% allowance for flotation costs, we get the following ranges and point estimates: 6.8-8.2% with a best estimate of 7.4%. The Ke estimates from the H-Model are higher than the averages derived using the single-stage model. This is because the model implicitly assumes that growth rates will gravitate to longer term average rates, which were higher than the implied rates using 2016 data only. I weight the estimates from the constant-growth model and the H-Model equally in arriving at my final DCF estimates.

A summary of the DCF estimates determined above is provided in Table 15 for the market and for Alberta utilities. The DCF analysis suggests a 7.7% required return on the market with a range of 6.6-8.1%. As discussed previously, this estimate equals exactly my CAPM estimate of 7.7% and is consistent with current estimates of finance experts and historical long-term real stock returns. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return with a range of 5.5-8.2% and a best estimate of 6.9%. This estimate is 1.3% below my DCF estimate for the market (if we also adjusted the market estimates 50bps for flotation costs), which is consistent with the below-average risk of utilities.

TABLE 15

DCF ESTIMATE SUMMARY

Year	Model	Minimum	Maximum	Best Estimate	Flotation Costs Adj.	Range	Final Estimate
Panel A: Market Estimates							
Single-Stage		6.6	8.1	7.4	0.50	7.1-8.6	7.9
H-Model		7.95	8.03	8.0	0.50	8.45-8.53	8.5
Combined		6.6	8.1	7.7	0.50	7.1-8.6	**8.2**
Panel B: Utility Estimates							
Single-Stage		5.0	7.2	5.9	0.50	5.5-7.7	6.4
H-Model		6.3	7.7	6.9	0.50	6.8-8.2	7.4
Combined		5.0	7.7	6.4	0.50	5.5-8.2	**6.9**

3.2.4. Utilities' Experts' DCF Estimates

I disagree with the utilities' experts' use of analyst earnings growth estimates because they are simply too high. This stance is consistent with the following statement of the Commission in the 2013 GCOC Decision:

> For example, analysts' forecasts of growth rates are forward-looking and aim to expressly account for events expected in the future. However, these same forecasts tend to incorporate a **high degree of subjectivity** and may be **overly optimistic**.[57]

Consistent with its concerns regarding the use of overly optimistic and subjective forecasts that are assumed in perpetuity, in the 2016 GCOC Decision, the Commission confirmed its policy of **not** accepting growth estimates that exceed those of expected nominal GDP growth noting:

> Consistent with its determinations in prior GCOC decisions, the Commission **will not accept**, in a single-stage DCF model, the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate for the economy.[58]

As a result, the Commission did **not** consider the single-stage DCF estimates of Mr. Hevert or Dr. Villadsen in 2016, since the single-stage growth estimates used by both experts violated the condition noted above. Nonetheless, Table 16 below shows clearly that the single-stage DCF Canadian sample estimates of all three utilities' experts should be rejected in these proceedings for exactly the same reason. In other words, they all use growth rates in

[57] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 180 [emphasis added].
[58] Decision 20622-D01-2016, 2016 Generic Cost of Capital, para. 287 [emphasis added].

perpetuity that exceed (by a wide margin) their own estimates for nominal GDP growth in Canada, with the average growth rate used (i.e., 7.25%) being a full 3.01% above the average GDP growth rate estimate of 4.24% - or 71% higher.

TABLE 16

CANADIAN SINGLE STAGE DCF ESTIMATES OF UTILITIES' EXPERTS

Expert	Growth Rate used in DCF	Nominal GDP Growth Rate Estimate	Initial Estimate of Cost of Equity (Ke)	Ke Estimate using GDP Growth Rate
Dr. Villadsen	8.3%	3.85%	13.1%	8.5%[59]
Mr. Hevert	7.5%	5.02%	11.35%	8.8%[60]
Mr. Coyne	5.96%	3.85%	10.85%	8.6%[61]
AVERAGE	**7.25%**	**4.24%**	**11.77%**	**8.63%**

Table 16 also provides the single-stage DCF estimates that would have resulted if the utilities' experts had used their own nominal GDP estimates, and hence not violated this condition. The resulting equity cost estimates decline substantially (by an average of 3.14%), as one would expect. They remain elevated (i.e., averaging 8.6%) because even the assumption of nominal GDP growth (i.e., average growth) is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for dramatic growth.[62] This point was also acknowledged previously by the Commission, at in the 2013 GCOC Decision:

> However, the Commission is also mindful that, as both experts acknowledged, **the GDP growth rate may be an ambitious target** for long-run earnings growth in respect of low-risk, mature, utilities.[63]

So, in summary, all of the single-stage Canadian DCF estimates provided by the utilities' experts should be rejected since they use growth rates that exceed nominal GDP growth rates. Even if we adjusted their single-stage DCF estimates downward by using GDP growth,

[59] Exhibit 22570-X0428, Information Response to Villadsen-UCA-2017NOV21-016(e).
[60] Exhibit 22570-X0496, Information Response to Hevert-UCA-2017NOV21-020(b.
[61] Exhibit 22570-X0310, Information Response to Coyne-UCA-2017NOV21-017. See also Exhibit 22570-X0328, Coyne-UCA-2017NOV21-017 a) Attachment.
[62] Hence the fact that the average growth estimates obtained using analyst estimates are much higher than expected GDP growth rates indicates that concerns regarding overly optimistic analyst estimates are valid.
[63] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].

these estimates would still be too high, since this represents an ambitious growth target for regulated Alberta utilities.

I now turn my attention to the utilities' experts' multi-stage DCF estimates. In the 2016 GCOC Decision, the Commission noted:

> Dr. Cleary further noted that Dr. Villadsen's growth estimates are above the long-term nominal growth rate for 10 years and, therefore, violate the upper limit on growth in the DCF model from the 2013 GCOC decision.[64]

This statement is referring to Dr. Villadsen's multi-stage DCF estimates. The rationale for this statement is as follows. First, let's denote g_{GDP} as the expected growth rate of nominal GDP. Since the growth rates used by the utilities' experts exceed g_{GDP} during years 1-10, and they then use g_{GDP} for years 11 to infinity, then this is equivalent to using one constant growth rate from now to infinity that is greater than g_{GDP}. This is simply a mathematical fact, which I illustrate below (using a time horizon of 100 years for simplicity purposes):

> Suppose: g(years 1-5) = 7%; g(years 6-10) = 5%; and, g(years 11-100) = 4% (which we will assume equals g_{GDP}).
>
> We can solve the equation below for "g_{LT}" to find the one constant perpetual growth rate that would result in \$1 growing to the same amount after 100 years, as it would have if it grew by 7% for the next five years, then 5% for the next five years, then grew by 4% from years 11 to infinity:
>
> $$(1.07)^5 \times (1.05)^5 \times (1.04)^{90} = (1 + g_{LT})^{100}$$
>
> $$(61.0753)^{1/100} - 1 = g_{LT}$$
>
> So, **g_{LT} = 4.20% which is > 4% (i.e., g_{GDP})**
>
> This is the implied constant perpetual growth rate from time 0 to infinity that is equivalent to 7% growth for the next five years, 5% for the following five years, then 4% to infinity.

[64] Decision 20622-D01-2016, 2016 GCOC Decision, para. 264.

All three utilities' experts' multi-stage DCF estimates begin with very high growth rates in year 1 (i.e., Villadsen – 8.3%; Hevert – 7.5%; and, Coyne – 5.96%). Their models work such that these high growth rates decline eventually (i.e., after 10 *long* years) to a somewhat ambitious long-term terminal growth rate (i.e., estimated nominal GDP growth). Hence, all of their multi-stage DCF estimates clearly violate the condition that the Commission has expressed with regards to using growth rates in a single-stage DCF model that exceed expected nominal GDP growth. In other words, the implied constant perpetual growth rate (i.e., g_{LT}) from the growth rates used in Dr. Villadsen's multi-stage DCF estimates would exceed her estimate of 3.85% for Canadian nominal GDP growth. Similarly, the implied perpetual growth rates for Mr. Hevert and Mr. Coyne would exceed their estimates of Canadian nominal GDP growth of 5.02% and 3.85% respectively. Since all of their estimates clearly violate this condition, they should all be rejected. This explains why they all obtain such high cost of equity estimates using their multi-stage DCF models.

3.3. Bond Yield Plus Risk Premium Estimates

The BYPRP approach adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[65] and by over 50 percent of Canadian CFOs.[66]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable

[65] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AC.
[66] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" Multinational Finance Journal 15-3, 2011. This article is appended to this evidence as Exhibit AE.

market-determined bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

This approach provides useful reasonableness checks on CAPM and other estimates, and employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s. In fact, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta.

The first step is to obtain an estimate of the cost of long-term yields on a typical utility. As of November 15, 2017 the yield on long-term A-rated Canadian utility bonds was 3.51% according to the Bloomberg data used to construct Figure 3. This number is close to the yields on outstanding Canadian utility bonds around the same time. For example the following yields were observed as of December 28, 2017:[67]

- CU Inc. bonds maturing November 19, 2046 – yield was 3.43%
- FortisAB Inc. bonds maturing September 21, 2046 – yield was 3.42%
- Hydro One bonds maturing October 19, 2046 – yield was 3.48%

This evidence implies that 3.5% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of

[67] http://www.pfin.ca/canadianfixedincome/Default.aspx, December 28, 2017.

2.5%. Combining this information, I obtain the following 2018-2019 estimates for Ke according to this approach:

Minimum: Ke = 3.5 + 2 = 5.5%

Maximum: Ke = 3.5 + 3 = 6.5%

Best Estimate: Ke = 3.5 + 2.5 = 6.0%

If we add 50 bp for flotation costs, we end up with Ke estimates in the 6-7% range, with a **best estimate of 6.5%**. This is 50 bp lower than my estimate in the 2016 GCOC Proceeding, which reflects the fact that A-rated bond yields have declined to 3.5% from about 4% at the start of 2016 when I prepared my evidence in that proceeding. This 6.5% estimate is 1% above my CAPM estimate of 5.5% and 0.40% below my DCF estimate of 6.9%.

Mr. Hevert calculates ROE estimates using what he claims is the BYPRP approach. However, he implements his BYPRP model by finding the difference between allowed ROEs in the U.S. and then comparing these allowed ROEs to Government of Canada bond yields to determine the Canadian figures, and by comparing the allowed ROEs to U.S. government bond yields to determine the U.S. figures. This is incorrect, since the BYPRP model, according to the CFA literature (and numerous other textbooks), and which is commonly used in analyst reports, adds a risk premium to the present yield on a firm's outstanding publicly-traded long-term bonds.[68] It therefore estimates a market-based return based on the yield on a company's outstanding bonds, which is reflective of market yield spreads. It does not use government yields, nor does it use ROEs and it certainly does not use allowed ROEs. Furthermore, the Commission has not applied allowed ROEs in other jurisdictions in previous decisions, including the 2013 GCOC Decision and the 2016 GCOC Decision.

As a result, in the 2016 GCOC Decision, the Commission did not place any weight on the results of Mr. Hevert's BYPRP model:

[68] For example, refer to page 77, Equity Asset Valuation, 3rd Edition, Pinto, Henry, Robinson and Stowe, 2015, John Wiley & Sons Inc., New Jersey. An excerpt is appended to this evidence as Exhibit BA.

> Consistent with its determinations in the 2009 GCOC decision, the Commission did not place any weight on the results of Mr. Hevert's and Dr. Villadsen's risk premium models that use the authorized ROEs granted by the U.S. regulators.[69]

Given that nothing has changed with respect to his BYPRP model or his implementation of it, his estimates should also be rejected in the current proceeding. His model uses U.S. allowed ROEs (which the Commission does not accept), it has no theoretical support, and there is no rationale supporting the relevance of a comparison of Government of Canada bond yields to allowed ROEs for regulated utilities in the U.S. (which may or may not have anything to do with existing market conditions).

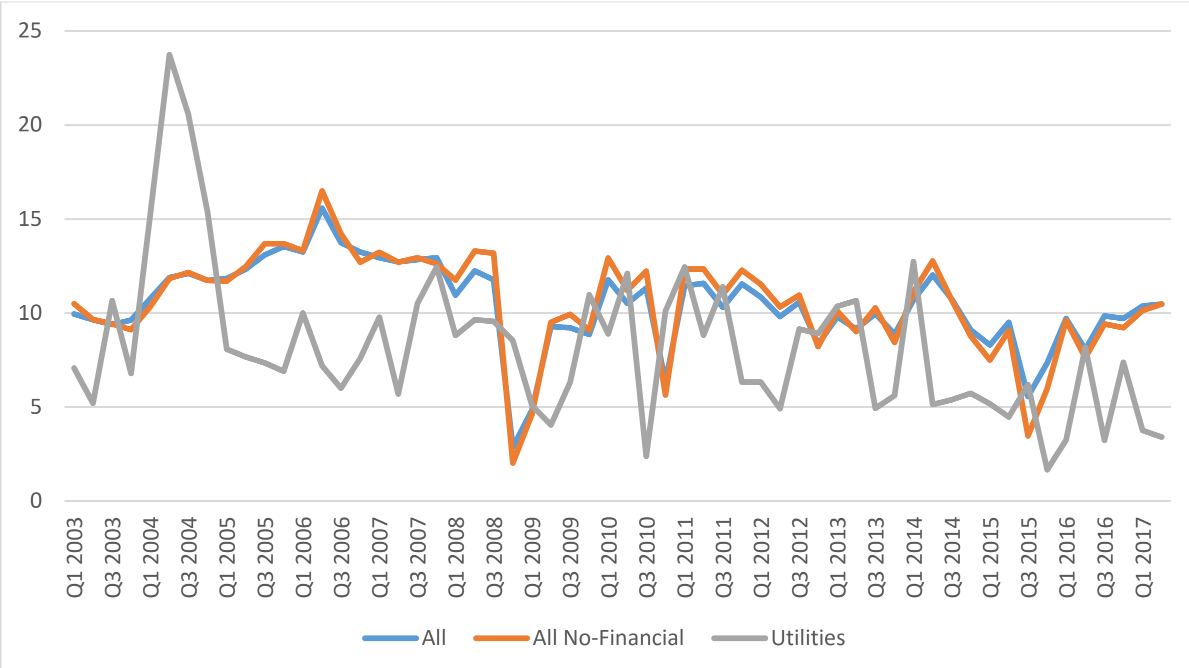
3.4. ROEs and Price-to-Book Ratios

Figure 13 depicts annualized quarterly ROE data for Canadian firms and Canadian utilities from Q1-2003 to Q2-2017. Over this period, the average ROE for all companies was 10.5%, 10.6% for all non-financial companies, and 8.2% for utilities. We can see that it was generally a good period for all types of companies in terms of ROEs, which fell between 2.9 and 15.6% for all companies, 2.0 and 16.5% for all non-financials, and 1.7 and 23.7% for utilities. The working papers for Figure 13 are appended to my evidence as Exhibit L.

[69] Decision 20622-D01-2016, 2016 GCOC Decision, para. 255

FIGURE 13

CANADIAN ROEs– Q1-2003 to Q2-2017



Data Source: CANSIM.

Table 17 provides similar positive results for Alberta utilities over the 2011 to 2016 period according to their Rule 005 reports with annual averages ranging from 8.8% to 9.7%, and always above the allowed ROE. The six-year overall average was 9.38%, which is 0.93% above the average allowed ROE over the period of 8.45%. So overall, we can say that these utilities have generated ROEs that were generally above the allowed rates of 8.75% (2011-12) and 8.3% (2013-16), with Alberta ROEs averaging 9.52% since 2013, or 1.22% above the allowed ROE of 8.3%. The average ROE of 9.4% is higher than the 2007-Q2/2017 average of 8.2% provided in Figure 16, below, for Canadian utilities, and the 2007-2016 average of 8.77% provided earlier in Table 12 for the Canadian utilities used in the DCF analysis.

TABLE 17

REPORTED ROEs – ALBERTA UTILITIES 2011-2016

Reported ROEs	2016	2015	2014	2013	2012	2011	Average	Median
Fortis Alberta	9.70%	11.12%	9.77%	9.49%	9.99%	9.73%	9.97%	9.75%
ATCO Elec Dist	13.03%	9.90%	9.74%	10.99%	12.14%	11.50%	11.22%	11.25%
ATCO Gas	12.93%	11.10%	10.95%	11.86%	11.01%	10.98%	11.47%	11.06%
AltaLink	8.21%	8.44%	8.44%	8.77%	9.28%	9.48%	8.77%	8.61%
ATCO Pipelines	11.39%	9.80%	10.31%	10.16%	11.16%	11.53%	10.73%	10.74%
ATCO Elec Trans	9.14%	8.23%	8.91%	9.84%	10.66%	9.87%	9.44%	9.49%
AltaGas	5.83%	6.16%	11.27%	12.50%	10.17%	6.19%	8.69%	8.18%
ENMAX Dist	9.93%	6.15%	7.82%	8.05%	10.22%	6.71%	8.15%	7.94%
ENMAX Trans	10.33%	11.48%	7.09%	5.90%	0.49%	4.08%	6.56%	6.50%
EPCOR Dist	8.98%	10.37%	10.31%	9.74%	8.10%	8.03%	9.26%	9.36%
EPCOR Trans	6.94%	8.90%	11.59%	7.17%	10.82%	8.36%	8.96%	8.63%
Average	9.67%	9.24%	9.65%	9.50%	9.46%	8.77%	9.38%	9.48%
Median	9.70%	9.80%	9.77%	9.74%	10.22%	9.48%	9.79%	9.76%
Allowed ROEs	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	8.45%	8.30%

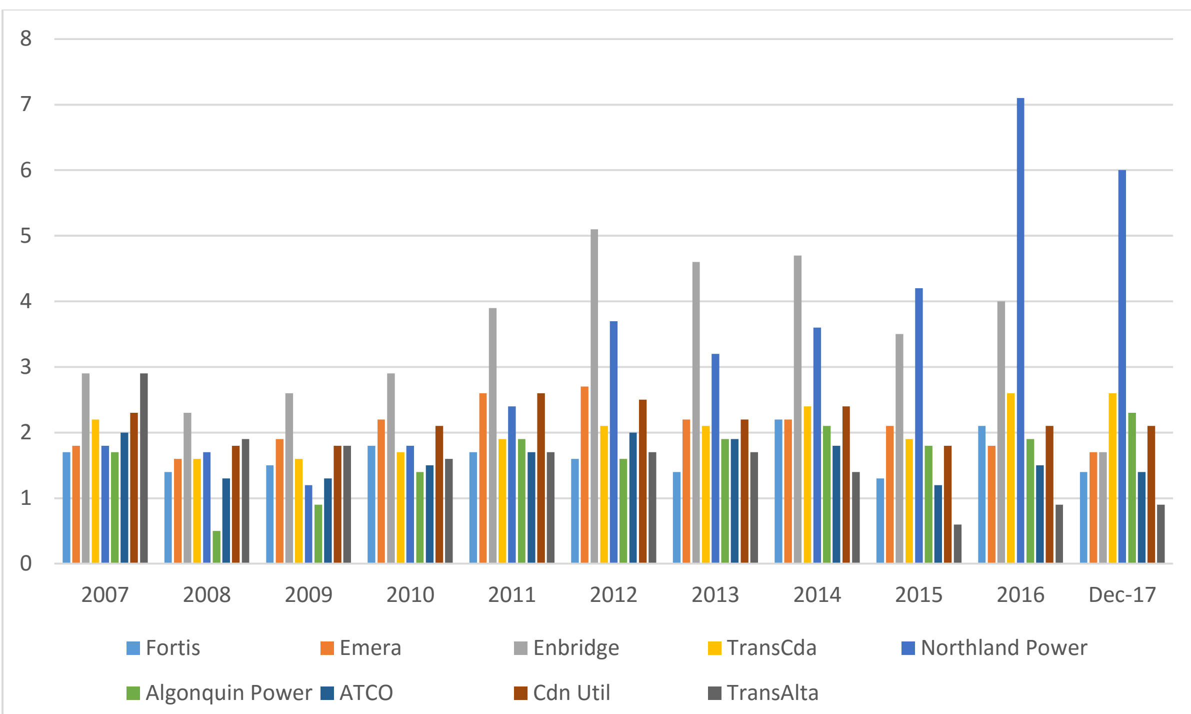
Data Source: Rule 005 reports.

ROE data suggest that Alberta utilities have earned an ROE that is almost as much as the average Canadian company, yet we know that they are less risky than average. In fact, the reported ROE numbers are above the required return estimates determined using the CAPM, DCF and BYPRP approaches, with best estimates of 5.5%, 6.9% and 6.5% and which ranged from 4.1% to 8.7%. All of this suggests that Alberta utilities would make attractive investments. Certainly, from an investor's point of view, low-risk utilities that have regulated returns that exceed *required* rates of return based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 5.5% figure that was determined above. If the utility earned the currently allowed ROE of 8.5%, then that investor would surely be pleased. Of course, this does not mean that the actual return on the stock was 8.5%; however there is an obvious relationship between the two. I will examine this relationship by reference to P/B ratios and stock returns.

I begin by considering the P/B ratios for the utilities discussed previously in the DCF analysis. The individual P/B ratios for the firms are presented in Figure 14. It is obvious that almost all of the ratios are above 1 throughout the entire period, with the exception of the P/B ratios for Transalta since 2015, and for Algonquin in 2008 and 2009. The summary statistics provided in Table 18 show that the average P/B ratio has generally exceeded 2 since 2011, and is presently in the 1.85 to 2.23 range, depending on which sub-set of firms is considered. The working papers for Figure 14 and Table 18 have been appended to my evidence as Exhibit M.

FIGURE 14

UTILITY P/B RATIOS – 2007-Dec 2017



Data Source: Morningstar at www.morningstar.ca.

TABLE 18

P/B RATIO SUMMARY STATISTICS (2006-Dec 2017)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Dec-17
Average	2.14	1.57	1.62	1.89	2.27	2.56	2.36	2.53	2.04	2.67	2.23
Median	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.10	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	4.20	7.10	6.00
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.40	0.60	0.90	0.90
Average excl TransAlta and Northland	2.09	1.50	1.66	1.94	2.33	2.51	2.33	2.54	1.94	2.29	1.89
Median	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.10	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	2.60
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.80	1.20	1.50	1.40
Average (Fortis, Emera, Enbridge, TransCda)	2.15	1.73	1.90	2.15	2.53	2.88	2.58	2.88	2.20	2.63	1.85
Median	2.00	1.60	1.75	2.00	2.25	2.40	2.15	2.30	2.00	2.35	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	2.60
Min	1.70	1.40	1.50	1.70	1.70	1.60	1.40	2.20	1.30	1.80	1.40

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least "fair," if not above fair. This is consistent with the Commission's statement in the 2011 GCOC Decision. The Commission confirmed the usefulness of P/B ratios in the 2013 GCOC Decision, noting:

> Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to

attract investment in the capital markets at reasonable rates and maintain its financial integrity.[70]

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[71] P/B = (ROE – g) / (Ke – g)

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke. This is consistent with the discussion above. If we "plugged" the average 2003-Q2/2017 utility index ROE of 8.2% into the equation, as well as current average P/B ratios of 2.23, 1.89, and 1.85, and then used a 3% long-term growth rate, we would get implied Ke figures of 5.33%, 5.75% and 5.81% respectively. These estimates are 33-81 basis points above my CAPM estimate of 5% provided above if we subtract the 0.50% that was added for financial flexibility, and are in line with, but slightly below, my single-stage DCF estimate of 5.9% (before the 0.5% adjustment). While I will not assign any weight to this estimate for purposes of determining Ke, the bottom line of this discussion is that the P/B ratios for utilities reported above indicate that Canadian utilities appear to be earning a satisfactory (or more than satisfactory) ROE, and have done so for quite some time.

3.5. Summary of ROE Calculations

I have weighted all three estimates equally, as I did in my 2013 and 2016 evidence, because all three methods are used in practice. CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to DCF approaches, they were used by:[72]

- only 15% of U.S. CFOs - versus over 70% for CAPM;[73]
- about 12% of Canadian CFOs - versus close to 40% for CAPM;[74]

[70] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 221.
[71] This is true if we use the following sustainable growth rate for "g" in the DDM: g = (1 – payout) × ROE.
[72] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."
[73] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AD.

- the majority of investors.[75]

These advantages also make CAPM more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also gave equal weighting to the BYPRP approach which is more widely used than DCF approaches due to its intuitive nature, and because it adjusts for both borrowing rates and risk. Thus the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such I believe it is intuitively sound and hence BYPRP estimates are excellent reflections of existing market conditions.

Based on an equal weighting of the three approaches, I determine the following best estimate for Alberta utility ROEs:

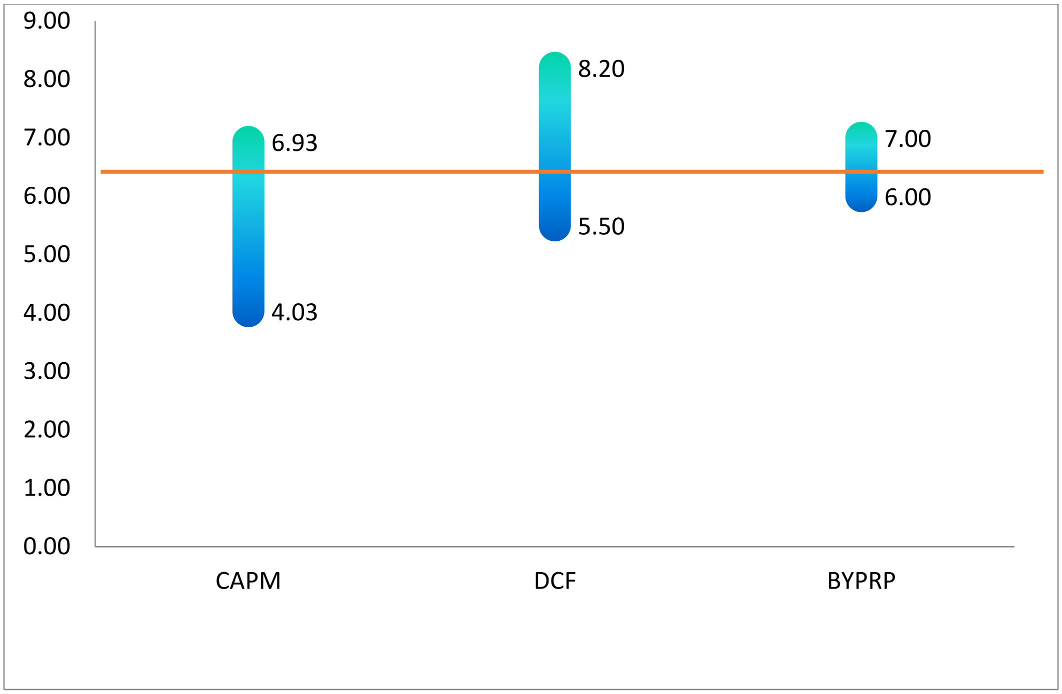
$$Ke = (1/3)(5.5) + (1/3)(6.9) + (1/3)(6.5) = \mathbf{6.3\%}$$

This estimate lies centrally in the estimate ranges for the three models, as depicted in Figure 15 below.

[74] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AE.
[75] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AF.

FIGURE 15

ROE ESTIMATE RANGES



This estimate is very reasonable when compared to expected long-term overall stock market returns in the 6-9% and a long-term expected market return of 7.5%, when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 6-9% range are consistent with current long-term forecasts by market professionals and with experienced long-term real stock returns of 5.6-7.4%. The ROE estimate is also consistent with our current low interest rate and low risk environment, which can be expected to change only gradually over the next few years.

4. CAPITAL STRUCTURE ISSUES

4.1. Background

4.1.1. Alberta Utilities' Operating Environment

The utilities provided several debt rating reports during these proceedings, including 16 full reports that applied to Alberta operating utilities - nine from S&P (six – 2017; three -2016), and seven from DBRS (four – 2017; three – 2016). Eight of the nine S&P reports rate the respective utility as "Excellent" with respect to business risk, with the lone exception being the "Strong" business risk rating given to AltaGas for 2017. While DBRS does not provide an explicit business risk rating, four of the seven reports identify "low business risk" as the respective utility's #1 strength. For the other three we can observe: ENMAX's 2017 report suggests the #1 strength is "predictable, steady regulated business with growing earnings;"[76] CU Inc.'s 2017 report states the #1 strength is "low-risk regulated business;"[77] and, AltaGas's 2017 report suggests the top two strengths are "Regulated and fee-based earnings with strong counterparties" and "Stable and diversified operations", respectively.[78] These types of statements echo the sentiment in previous debt rating reports. For example, during the 2016 GCOC Proceeding, all 15 rating reports for the Alberta utilities from calendar year 2015 refer to low business risk as the #1 strength (in the case of DBRS reports) or rated the utilities as Excellent in terms of Business Risk (in the case of S&P reports).[79] Strong regulatory support is generally cited as a contributing factor to this low business risk assessment. For example, S&P stated on page 4 of its January 26, 2017 rating report for AltaLink L.P. that:

> Our view of ALP's business risk largely reflects our opinion of the Alberta Utility Commission's (AUC) regulatory framework that supports stable and predictable cash flow, a key credit strength and ongoing determinant for the ratings.[80]

I concur with these assessments – regulated Alberta operating utilities possess low business risk and enjoy solid regulatory support.

The utilities' experts have argued that the performance-based regulation ("**PBR**") framework has created additional risks for Alberta utilities (as they argued in the 2013 GCOC Proceeding), and that the 2018-2022 PBR framework creates new challenges. Mr. Bell's evidence clearly refutes these arguments. He shows that, since implementation, the return has

[76] Exhibit 22570-X0136, Appendix 3.4, DBRS Credit Rating Report for ENMAX Corporation, PDF page 2.
[77] Exhibit 22570-X0164, ATCO Utilities Credit Rating Reports, PDF page 21.
[78] Exhibit 22570-X0118, AUI MFR – Credit Rating Agency Reports, PDF page 11.
[79] Technically, the Fortis Inc. January 5, 2015 report states that its # 1 strength is "strong and stable dividends from low-risk utilities", which is essentially the same as saying low business risk.
[80] Exhibit 22570-X0151, AML MFR – Equity Analyst and Credit Rating Reports, PDF Page 22.

increased and the standard deviation of returns has decreased during the PBR term for the PBR utilities. In effect, the PBR utilities did better than under cost of service ("**COS**"), and as such, the regulatory risk under PBR is actually less than under COS, resulting in lower business risk for PBR utilities. He also refutes suggestions that the 2018-2022 PBR framework will add significant new risk.

The utilities also argue, as they did in the 2013 GCOC Proceeding and the 2016 GCOC Proceeding, that Decision 2013-417 (the "**UAD Decision**") has created additional risk for Alberta utilities that warrants additional compensation. However, as in the prior proceedings, they do not provide any tangible evidence to support this conjecture. Mr. Bell refutes the entire notion that the utilities should receive compensation for the risk associated with potential losses, while at the same time being in position to realize any gains – it is simply not fair. In other words, in their discussion of the UAD Decision, the utilities do not account for the fact that the UAD Decision also holds the possibility that *gains* will accrue to shareholders, as noted in the 2013 GCOC Decision, where the Commission concluded:

> Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores Block* decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.
>
> In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.[81]

Despite the arguments put forth by the utilities' experts, as noted above, Alberta utilities continue to be rated excellent with respect to business risk by S&P, while low business risk is the #1 strength in DBRS reports. This is what one would expect for mature regulated

[81] Decision 2191-D01-2015, 2013 Generic Cost of Capital, paras. 350-351.

transmission and distribution utilities operating virtual monopolies that are able to pass on legitimate costs to customers. My empirical analysis below confirms that Alberta utilities continue to operate in a low risk environment that enables them to earn above their allowed ROEs with very little volatility in income.

4.1.2. Economic Conditions and Alberta Utilities

Section 2 shows that global economic conditions have stabilized, as have Canadian capital market conditions. Real GDP growth for Alberta is estimated at 6.7% by the CB during 2017, well above average. Growth is expected to moderate to 2.1% in 2018 and 1.6% in 2019. Overall, we can say that the Canadian and Alberta economies are expected to grow at subdued, but healthy levels in the intermediate term. In any event, economic and capital market conditions are far from those existing at the peak of the 2008-2009 financial crisis, and have improved materially for both Alberta and Canadian capital markets since the time of the 2016 GCOC Proceeding.

It is important to note that regulated utilities are not as greatly influenced by economic cyclicality to the extent of traditional businesses. This is true of Alberta utilities. For example, in 2009, real GDP growth in Alberta was -4.1%, yet the average EBIT/Sales ratio for Alberta utilities was 29.1%, slightly above the 2005-2016 average of 28.9% as reported in Table 22, below, while the 2009 average of the individual utility EBIT growth rates was 17.3%, versus the 2005-2016 average of 9.3%. During 2009, the average ROE earned by Alberta utilities was 9.91% as reported in Table 20, which was 91 bp above the allowed ROE of 9.0%. Empirical evidence like this indicates that the earnings of Alberta utilities are resilient in the face of economic decline, which shows they have low business risk. I provide compelling evidence to support this conclusion in Sections 4.2 and 4.3.

4.2. A Quantitative Review of Alberta Utilities' Performance

This section provides a brief review of the performance of the Alberta utilities using information provided for the 2005-2016 period in their Rule 005 reports. Table 19 summarizes the growth in the aggregate figures for the Alberta utilities, excluding EPCOR, over the 2005-2016 period.[82] The working papers for Table 19 are appended as Exhibit N to my evidence.

Table 19 shows that aggregate revenue rose almost three-fold over this period from $1.6 billion to $4.4 billion, representing a compound growth rate of 9.6% per year. By comparison, real GDP growth from 2005-2016 in Alberta demonstrated compound annual growth of 2.2%. Over the same period, EBIT (a commonly used measure of operating income) rose more than threefold, representing an annual compound growth rate of 11.8%. The fact that EBIT grew faster than revenue indicates that regulatory support, including the numerous cost flow-through mechanisms in place, are working effectively and enabling firms to continue to earn solid profit margins on their revenues. This is further attested to by the fact that the EBIT/Sales ratio was 28.3% in 2005 and was even higher by 2016 (35.4%). Finally, we get a similar, if not stronger, message if we look at the figures for net income available to common equity, which grew close to five times the original amount, at an annual compound growth rate of 15.1%. Not surprisingly, the net income margins also increased from 11.0% to 18.9% - very healthy margins indeed. Overall, these figures show that 2005-2016 was a very good 12-year period for regulated Alberta utilities.

TABLE 19

ALBERTA UTILITIES GROWTH STATISTICS (2005-2016)

	Revenue	**EBIT**	**Net Income Available to CE**	**EBIT/Sales**	**NIACE/Sales**
2005	1,604.5	454.7	176.3	28.34%	10.99%
2016	4,389.1	1,554.7	831.4	35.42%	18.94%
Geometric Mean Growth	9.58%	11.83%	15.14%		
Alberta Real GDP Growth (Geometric Mean) 2005-2016[83]	2.18%				

[82] Table 19 includes the reported figures for Alberta utilities excluding EPCOR Distribution and Transmission (due to missing data in their 2005 Rule 005 reports).

[83] Alberta real GDP growth figures for 2005-2016 were obtained from the Conference Board of Canada at: http://www.conferenceboard.ca/hcp/provincial/economy/gdp-growth.aspx (December 30, 2017).

An even more compelling way of reviewing the performance of Alberta utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities – "where the rubber hits the road," so to speak. Table 20 provides such a comparison of the reported ROEs by Alberta utilities in their Rule 005 reports with the allowed ROEs. The yearly average and median figures show that Alberta utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average reported ROE was a mere 0.18% below the allowed ROE, while the median equalled it. We get a similar message if we look at the weighted average ROE ("**Wt Av ROE"**). This is estimated by weighting each utility according to its average revenue over the entire 2005-2016 period, relative to total revenue across all utilities over the entire period, which effectively gives larger weight to the larger utilities.[84]

[84] The corresponding weights are reported in Table 22.

TABLE 20

ALBERTA UTILITIES REPORTED ROEs (2005-2016)

	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
Fortis Alberta	9.70%	11.12%	9.77%	9.49%	9.99%	9.73%	9.63%	9.13%	9.19%	8.79%	10.28%	10.45%
ATCO Elec Dist	13.03%	9.90%	9.74%	10.99%	12.14%	11.50%	12.57%	12.62%	10.27%	10.26%	9.38%	9.10%
ATCO Gas	12.93%	11.10%	10.95%	11.86%	11.01%	10.98%	9.67%	11.57%	11.67%	10.83%	8.26%	5.81%
AltaLink	8.21%	8.44%	8.44%	8.77%	9.28%	9.48%	9.10%	9.30%	8.50%	9.20%	9.40%	10.60%
ATCO Pipelines	11.39%	9.80%	10.31%	10.16%	11.16%	11.53%	10.85%	10.88%	9.51%	8.21%	10.61%	10.19%
ATCO Elec Trans	9.14%	8.23%	8.91%	9.84%	10.66%	9.87%	10.21%	9.63%	8.74%	8.50%	9.28%	9.61%
AltaGas	5.83%	6.16%	11.27%	12.50%	10.17%	6.19%	4.86%	8.94%	8.75%	8.51%	8.93%	9.50%
ENMAX Dist	9.93%	6.15%	7.82%	8.05%	10.22%	6.71%	6.79%	10.39%	8.27%	5.08%	6.99%	9.50%
ENMAX Trans	10.33%	11.48%	7.09%	5.90%	0.49%	4.08%	6.61%	12.84%	9.34%	6.58%	10.85%	
EPCOR Dist	8.98%	10.37%	10.31%	9.74%	8.10%	8.03%	10.76%	4.48%	7.81%	9.82%	8.85%	9.16%
EPCOR Trans	6.94%	8.90%	11.59%	7.17%	10.82%	8.36%	9.71%	9.20%	11.12%	10.47%		
Average	9.67%	9.24%	9.65%	9.50%	9.46%	8.77%	9.16%	9.91%	9.38%	8.75%	9.28%	9.32%
Median	9.70%	9.80%	9.77%	9.74%	10.22%	9.48%	9.67%	9.63%	9.19%	8.79%	9.33%	9.50%
Max	13.03%	11.48%	11.59%	12.50%	12.14%	11.53%	12.57%	12.84%	11.67%	10.83%	10.85%	10.60%
Min	5.83%	6.15%	7.09%	5.90%	0.49%	4.08%	4.86%	4.48%	7.81%	5.08%	6.99%	5.81%
StDev	2.25%	1.87%	1.45%	1.96%	3.15%	2.37%	2.23%	2.28%	1.20%	1.72%	1.15%	1.42%
CV(ROE)	0.232	0.202	0.150	0.206	0.333	0.270	0.243	0.230	0.128	0.196	0.124	0.153
Wt Av ROE	10.46%	9.50%	9.73%	10.17%	10.32%	9.69%	9.86%	10.03%	9.52%	9.18%	8.92%	8.70%
Allowed ROEs	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%	9.00%	8.75%	8.51%	8.93%	9.50%
Diff Avg	**1.37%**	**0.94%**	**1.35%**	**1.20%**	**0.71%**	**0.02%**	**0.16%**	**0.91%**	**0.63%**	**0.24%**	**0.35%**	**-0.18%**
Diff Median	**1.40%**	**1.50%**	**1.47%**	**1.44%**	**1.47%**	**0.73%**	**0.67%**	**0.63%**	**0.44%**	**0.28%**	**0.40%**	**0.00%**
Diff Wt Avg	**2.16%**	**1.20%**	**1.43%**	**1.87%**	**1.57%**	**0.94%**	**0.86%**	**1.03%**	**0.77%**	**0.67%**	**-0.01%**	**-0.80%**

Table 21 provides the summary statistics for each utility over the period and aggregates them. These statistics show that ROEs averaged 9.33% across all utilities and all years, while allowed ROEs averaged 8.70%. The last three rows in this table show that the annual averages of reported ROEs exceeded the allowed ROEs over the 12-year period by 0.64%, with the annual median ROEs exceeding allowed ROEs by a 12-year average of 0.87%. The weighted annual average ROE exceeds the allowed average by an even higher margin of 0.97%, indicating that the larger utilities have been better than average at earning above the allowed ROE. This lends strong support to the evidence provided in Table 19, showing that Alberta utilities operate in a low risk environment that enables them to earn attractive returns

– i.e., since they are consistently able to earn their allowed ROEs or higher. This can be considered the strongest indication that the utilities possess low risk overall. The working papers for Table 20 and Table 21, as well as Table 17, produced above, are appended to this evidence as Exhibit O.

TABLE 21

SUMMARY STATISTICS – ALBERTA REPORTED ROEs (2005-2016)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Fortis Alberta	9.77%	9.72%	11.12%	8.79%	0.63%	0.065
ATCO Elec Dist	10.96%	10.63%	13.03%	9.10%	1.38%	0.126
ATCO Gas	10.55%	10.99%	12.93%	5.81%	1.89%	0.179
AltaLink	9.06%	9.15%	10.60%	8.21%	0.65%	0.072
ATCO Pipelines	10.38%	10.46%	11.53%	8.21%	0.92%	0.089
ATCO Elec Trans	9.39%	9.45%	10.66%	8.23%	0.72%	0.077
AltaGas	8.47%	8.84%	12.50%	4.86%	2.32%	0.274
ENMAX Dist	7.99%	7.94%	10.39%	5.08%	1.73%	0.216
ENMAX Trans	7.78%	7.09%	12.84%	0.49%	3.62%	0.466
EPCOR Dist	8.87%	9.07%	10.76%	4.48%	1.69%	0.190
EPCOR Trans	9.43%	9.46%	11.59%	6.94%	1.61%	0.171
Average	9.33%	9.34%	11.63%	6.38%	1.56%	0.175
Median	9.39%	9.45%	11.53%	6.94%	1.61%	0.171
Max	10.96%	10.99%	13.03%	9.10%	3.62%	0.466
Min	7.78%	7.09%	10.39%	0.49%	0.63%	0.065
StDev	1.03%	1.15%	1.02%	2.57%	0.88%	
CV(ROE)						
Wt Av ROE						
	Average	Median	Max	Min	StDev	
Allowed ROEs	8.70%	8.75%	9.50%	8.30%	0.38%	
Diff Avg	**0.64%**	**0.67%**	**1.37%**	**-0.18%**	**0.53%**	
Diff Median	**0.87%**	**0.70%**	**1.50%**	**0.00%**	**0.55%**	
Diff Wt Avg	**0.97%**	**0.99%**	**2.16%**	**-0.80%**	**0.80%**	

4.3. A Quantitative Assessment of Alberta Utilities' Risk

4.3.1. Business Risk

My examination of the Alberta utilities' operating and regulatory environment above suggests they possess low business risk. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great of an ability to flow through increases in their costs to their customers. As noted in Section 4.1, debt rating reports consistently suggest that the Alberta utilities have low business risk.

Most experts assessing "business risk" would agree that it refers to some variation of factors that cause uncertainty, or volatility, in operating income. For example, the following definition of business risk can be found in the CFA Institute's on-line Glossary of definitions: "The risk associated with operating earnings. Operating earnings are uncertain because total revenues and many of the expenditures contributed to produce those revenues are uncertain" This definition is consistent with the definition of business risk proposed by Dr. Roger Morin in the 2003 Newfoundland and Labrador Board of Commissioners of Public Utilities ("**PUB**") rate hearings, as noted in Order No. P.U. 19 (2003), quoted below:

> **<u>Business Risk</u>**
>
> Refers to the relative **variability of operating profits** induced by the external forces of demand for and supply of the firm's products, by the presence of fixed costs, by the extent of diversification or lack thereof of services, and by the character of regulation.[85]

This definition was accepted by the PUB at that time:

> The Board feels the above definitions are consistent and reasonable. The Board accepts these definitions and sees no particular conflict in terms of the evidence presented during the hearing.[86]

Similarly, during the 2016 GCOC Proceeding, in response to AML/EDTI-UCA-2016FEB-011,[87] Mr. Hevert confirmed that he was referring to "operating earnings" in the following passage from his evidence in the 2016 GCOC Proceeding discussing business risk:

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[85] Order No. P.U. 19 (2003), In the Matter of the 2003 General Rate Application filed by Newfoundland Power, page 31, source: http://www.pub.nl.ca/nfpower03/order/pu19-2003.pdf
[86] *Ibid.*

> Business risk reflects the uncertainty associated with owning the subject company's common stock, without the use of debt and/or preferred capital. Examples of the business risks generally faced by utilities include, but are not limited to, the regulatory environment, customer mix and concentration, service territory economic growth, capital intensity and size, and the degree of operating leverage, all of which have a direct bearing on earnings.[88]

In this section, I use a variation of a commonly used measure of operating income volatility, the coefficient of variation of the EBIT/Sales ratio (hereafter "**CV(EBIT/Sales)**"), to *quantify* a firm's level of business risk.[89] The CV is determined by dividing the standard deviation ("**SD**") of the EBIT/Sales ratio by the average EBIT/Sales level. The rationale for using the CV as a measure of EBIT/Sales volatility, rather than simply using the SD of EBIT/Sales, is that the SD is affected by the size of the average EBIT/Sales ratio. In other words, firms with larger EBIT/Sales ratios would have higher SDs of EBIT/Sales, even if they have less volatility, simply because the level of the EBIT/Sales figures used to determine the SD are higher. This is indeed the case in my analysis – for example, the average EBIT/Sales ratio across the Alberta utilities over this period is 28.9%, much higher than the U.S. utility sample average of only 15.9%.[90] The CV is more appropriate in such instances and is commonly used to measure volatility since it effectively "scales" the SD of EBIT/Sales when it is divided by the average level of EBIT/Sales.

This measure (i.e., CV(EBIT/Sales)) is calculated as the standard deviation of the EBIT/Sales ratio (2005-2016) divided by the average of the EBIT/Sales ratio over this period. Using the EBIT/Sales ratio rather than the level of EBIT is a valid measure of business risk, since it measures volatility in the operating profit margins for firms. It also has the advantage that, as a ratio, the expected value and past average values will often coincide since these profitability margins often tend to gravitate to some long-term average.

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[87] Exhibit 20622-X0164, Information Response to AML/EDTI-UCA-2016FEB-011.
[88] Exhibit 20622-X0082, AML Evidence of Robert Hevert, page 16, lines 13-17.
[89] For example, the 2013 CFA curriculum (Reading 28, page 351) refers to the use of CV(EBIT) as a measure of business risk, as do numerous finance and accounting texts such as Financial Management: Principles and Applications, 6th edition, by J. William Petty, Sheridan Titman, Arthur J. Keown, Peter Martin, John D. Martin, Michael Burrow, Hoa Nguyen, 2011, Pearson Higher Education.
[90] The fact that the U.S. utilities have a much lower average EBIT/Sales ratio in and of itself also indicates the U.S. utilities have higher business risk.

4.3.2. Alberta Utilities

Table 22 provides the CV(EBIT/Sales) ratios for the Alberta utilities over the 2005-2016 period. The average CV across all utilities is 0.154, while the median is 0.132 and the weighted average is 0.133. Most of the individual utility CV estimates fall between 0.10 and 0.15, with the exception of ATCO Pipelines, which has a CV of 0.057, and AltaGas and ENMAX Transmission, which have CVs of 0.376 and 0.250 respectively. Since these three utilities have relatively low weighting according to average revenue, the median and weighted average CV estimate is lower at 0.133. Table 22 also provides summary statistics for EBIT/Sales and EBIT growth for the Alberta utilities, which confirm the two points made earlier with respect to the discussion of the results reported in Table 19. Namely, the Alberta utilities have very healthy operating profit margins as measured by EBIT/Sales with average, median and weighted average figures of 28.9%, 27.1% and 29.0% respectively. They have also displayed substantial growth in EBIT over this decade with utility median growth rates across all utilities producing average, median and weighted averages of 9.3%, 9.1% and 10.4% respectively. The working papers for Table 22 are appended as Exhibit N to my evidence.

TABLE 22

CV(EBIT/SALES) ESTIMATES – ALBERTA UTILITIES (2005-2016)

	Weights (based on Average Revenue – 2005-2016)	CV (EBIT/Sales)	EBIT/Sales	EBIT Growth(median)
Fortis Alberta	11.3%	0.132	0.338	0.120
ATCO Elec Dist	17.0%	0.145	0.189	0.067
ATCO Gas	17.3%	0.098	0.255	0.098
AltaLink	12.6%	0.119	0.443	0.149
ATCO Pipelines	6.0%	0.057	0.387	0.053
ATCO Elec Trans	11.2%	0.147	0.468	0.199
AltaGas	3.6%	0.376	0.101	0.087
ENMAX Dist	7.7%	0.145	0.191	0.041
ENMAX Trans	1.5%	0.250	0.271	0.015
EPCOR Dist	9.7%	0.107	0.140	0.091
EPCOR Trans	2.1%	0.116	0.393	0.106
Alberta Utilities		**CV (EBIT/Sales)**	**EBIT/Sales**	**EBIT Growth(median)**
Average		**0.154**	**0.289**	**0.093**

Median	**0.132**	**0.271**	**0.091**
Max	0.376	0.468	0.199
Min	0.057	0.101	0.015
StdDev	0.088	0.125	0.051
Weighted Average	**0.133**	**0.290**	**0.104**

4.3.3. Comparing the Risk of Alberta Utilities to U.S. Utilities

The purpose of the analysis in this section is to provide quantitative evidence comparing the business risk of U.S. utilities used in the utilities' experts' evidence to that of the Alberta utilities. In particular, the evidence provided by the utilities relies heavily on U.S. samples based on the premise that such samples are of comparable risk to Alberta utilities, and therefore require no adjustments for comparison purposes. Therefore, in order to avoid debate over my U.S. sample selection during the 2016 GCOC Proceeding, I used the same U.S. utilities for comparison purposes as those used by Dr. Villadsen and Mr. Hevert respectively. At that time, I was able to find the required data for 37 of the 38 total firms used by either Dr. Villadsen and/or Mr. Hevert.[91] For the current proceeding, I cross-referenced these 37 utilities with the samples used by Dr. Villadsen, Mr. Hevert and Mr. Coyne, and only included firms that were in at least one of their samples. This left me with 32 U.S. utilities. This sample includes 18 of the 21 U.S. Electric Utility firms that Dr. Villadsen classified as regulated, 7 of the 9 U.S. Electric Utilities she classified as partially regulated, and 6 of the 9 utilities in her U.S. Gas sample – i.e., 31 of the 39 firms (i.e., 80%) she uses in these samples. It also includes 19 of the 25 U.S. utilities (i.e., 76%) used by Mr. Hevert, and 7 of the 11 U.S. utilities (i.e., 64%) used by Mr. Coyne. Hence it is a reasonable depiction of the U.S. utilities used by the utilities' experts.

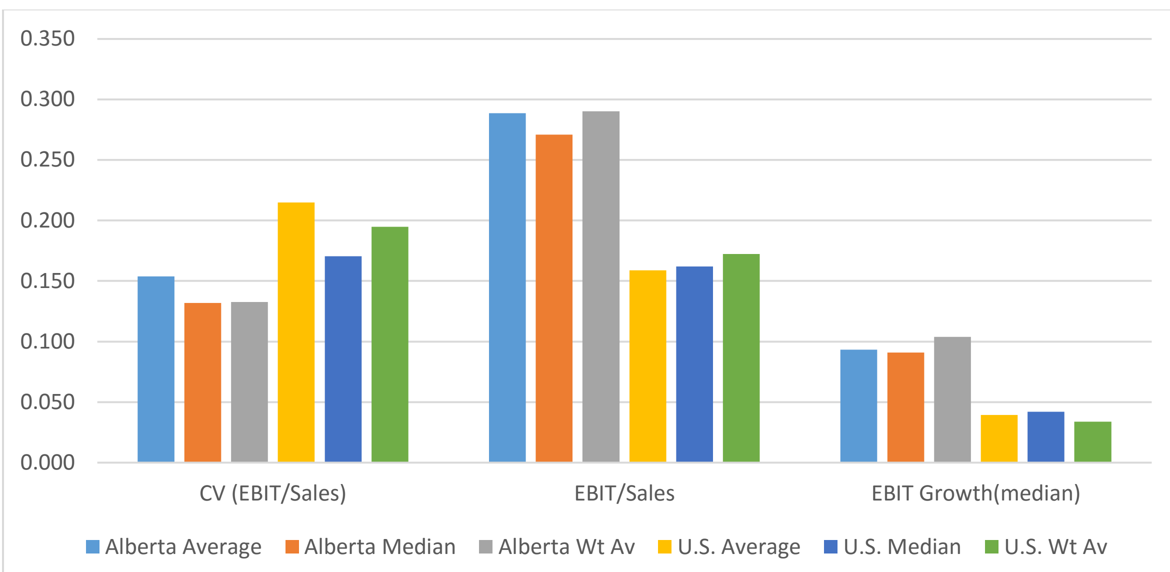
Figure 16 depicts a summary of the main results of this analysis. The evidence clearly shows that U.S. utilities have higher volatility in their EBIT/Sales ratios as measured by the CV(EBIT/Sales). The U.S. average, median and weighted average values for the CV(EBIT/Sales) are 0.215, 0.171 and 0.195 respectively, versus corresponding figures of 0.154, 0.132 and 0.133 for Alberta utilities. These figures show that the U.S. utilities in this sample display greater volatility in operating profit margins, as measured by EBIT/Sales. In

[91] There was some overlap in the chosen utilities, with 18 of the utilities being included in both of their U.S. proxy groups.

addition, Figure 16 shows clearly that the Alberta utilities have much higher operating profit margins with average, median and weighted average EBIT/Sales ratios of 0.289, 0.271 and 0.290 versus corresponding U.S. figures of 0.159, 0.162 and 0.172. Finally, the last bar chart in Figure 16 shows that the median annual percentage EBIT growth was also much higher for the Alberta utilities with average, median and weighted average figures of 9.3%, 9.1% and 10.4% versus corresponding U.S. figures of 3.9%, 4.2% and 3.4%. So overall, Figure 16 shows that Alberta utilities have less volatility in operating profit margins, which demonstrates lower business risk, while at the same time maintaining higher profit margins and higher growth in EBIT levels. This evidence shows clearly that the Alberta utilities have lower business risk than their U.S. counterparts in this sample. The working papers for Figure 16 are appended as Exhibit N (Alberta utilities), Exhibit P (U.S. utilities) and Exhibit Q (summary statistics) to my evidence.

FIGURE 16

ALBERTA VERSUS U.S. UTILITIES (2005-2016)



Data Source: Alberta data are obtained from the Rule 005 reports;
U.S. data are obtained from the Compustat database.

Table 23 provides the individual results for the U.S. utilities, confirming that the patterns displayed in Figure 16 are not driven by the use of averages or medians. In particular, I would note that only 8 of the 32 CV estimates for the U.S. utilities is below the median

Alberta CV estimate of 0.132, with the remaining 24 CV estimates being above this level, some being much higher. None of the individual U.S. utility EBIT/Sales average ratios is higher than the Alberta median figure of 27.1%, and only 1 of the 32 median EBIT growth figures is as high as the median growth figure of 9.1% for the Alberta utilities. So, the conclusions that the U.S. utilities display greater operating income volatility, despite lower EBIT margins and growth in EBIT, stands firmly. The working papers for Table 23 are appended as Exhibit P to my evidence.

TABLE 23

CV(EBIT/SALES) ESTIMATES – U.S. UTILITIES (2005-2016)

	CV (EBIT/Sales)	EBIT/Sales	EBIT Growth (median)
ALLETE INC	0.069	0.160	0.035
ALLIANT ENERGY CORP	0.131	0.156	0.037
AMEREN CORP	0.094	0.195	0.048
AMERICAN ELECTRIC POWER CO	0.083	0.192	0.057
ATMOS ENERGY CORP	0.385	0.108	0.057
CENTERPOINT ENERGY INC	0.170	0.127	0.028
CMS ENERGY CORP	0.772	0.112	0.017
CONSOLIDATED EDISON INC	0.167	0.163	0.056
DOMINION RESOURCES INC	0.213	0.237	-0.003
DTE ENERGY CO	0.203	0.130	-0.028
EDISON INTERNATIONAL	0.056	0.184	0.022
EL PASO ELECTRIC CO	0.165	0.172	0.071
ENTERGY CORP	0.118	0.175	-0.009
FIRSTENERGY CORP	0.235	0.167	0.056
IDACORP INC	0.124	0.196	0.068
MGE ENERGY INC	0.202	0.185	0.059
NEW JERSEY RESOURCES CORP	0.374	0.054	0.088
NEXTERA ENERGY INC	0.250	0.204	0.060
NORTHWEST NATURAL GAS CO	0.139	0.169	-0.001
NORTHWESTERN CORP	0.203	0.148	0.041
OGE ENERGY CORP	0.323	0.161	0.043
OTTER TAIL CORP	0.385	0.090	0.030
PG&E CORP	0.078	0.167	0.017
PINNACLE WEST CAPITAL CORP	0.157	0.216	0.002
PNM RESOURCES INC	0.457	0.144	0.030
PORTLAND GENERAL ELECTRIC CO	0.155	0.146	0.055
PUBLIC SERVICE ENTRP GRP INC	0.157	0.234	0.024
SCANA CORP	0.289	0.178	0.067
SOUTH JERSEY INDUSTRIES INC	0.171	0.143	0.048
SOUTHWEST GAS CORP	0.143	0.118	0.037
WGL HOLDINGS INC	0.230	0.094	0.091
XCEL ENERGY INC	0.181	0.156	0.056
	CV (EBIT/Sales)	**EBIT/Sales**	**EBIT Growth**
Average	**0.215**	**0.159**	**0.039**
Median	**0.171**	**0.162**	**0.042**
Max	0.772	0.237	0.091

Min	0.056	0.054	-0.028
StdDev	0.142	0.041	0.028
Weighted Average	**0.195**	**0.172**	**0.034**

While this sample of U.S. utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Alberta counterparts. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts, although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions.

One effective way to compare overall riskiness of Alberta utilities to their U.S. counterparts would be to compare their ability to earn their allowed ROEs, as I did for the Alberta utilities in Tables 20 and 21. Recall that Alberta utilities earned ROEs above the allowed ROEs on average every year from 2006-2016, and that over the entire 2005-2016 period earned ROEs exceeded allowed ROEs by an annual average (median) of 0.64% (0.87%) with a revenue-weighted annual average of 0.97%. Unfortunately, it is not practical to compare the earned ROEs to allowed ROEs for the U.S. utilities because the U.S. utilities included in the U.S. proxy groups are primarily holding companies that own several distinct operating utilities, which operate in numerous jurisdictions.

Another effective way of comparing the riskiness of Alberta utilities to that of the U.S. utility proxy groups is to compare the volatility in earned ROEs. This is a measure of total risk (i.e., business and financial risk), since financial leverage influences net income, whereas EBIT is not influenced directly by financial leverage. Table 24 provides the summary statistics for earned ROEs for the U.S. sample, identical to those provided for the Alberta utilities in Table 21. Table 24 shows that the reported ROEs are higher for the U.S. utilities on average, with an average across all 32 utility averages of 9.77%, versus the corresponding figure of 9.33% across the Alberta utilities. This is expected, since allowed ROEs in the U.S. have been higher than in Canada over the several years. However, if we look at the last column in Table 24 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the U.S. firms to the results in the last column of Table 21 for Alberta utilities, we can see that the

U.S. utilities displayed much greater volatility in ROEs than the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the U.S. utilities were 0.413 and 0.236 respectively, versus corresponding figures of 0.175 and 0.171 for Alberta utilities as reported in Table 21. The working papers for Table 24 are appended to my evidence as Exhibit R.

TABLE 24

SUMMARY STATISTICS – U.S. REPORTED ROEs (2005-2016)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
ALLETE INC	8.43%	7.94%	11.80%	6.56%	1.46%	0.174
ALLIANT ENERGY CORP	10.73%	10.70%	16.56%	4.68%	2.84%	0.265
AMEREN CORP	5.10%	8.26%	9.32%	-14.72%	7.39%	1.449
AMERICAN ELECTRIC POWER CO	9.84%	10.03%	13.27%	3.51%	2.77%	0.281
ATMOS ENERGY CORP	9.28%	9.30%	10.11%	8.57%	0.48%	0.052
CENTERPOINT ENERGY INC	12.69%	13.63%	32.14%	-19.99%	13.59%	1.072
CMS ENERGY CORP	10.11%	12.57%	13.71%	-10.00%	7.20%	0.712
CONSOLIDATED EDISON INC	9.46%	9.10%	12.45%	8.58%	1.18%	0.125
DOMINION RESOURCES INC	15.10%	14.56%	27.16%	2.86%	6.75%	0.447
DTE ENERGY CO	9.91%	9.24%	16.59%	8.27%	2.50%	0.253
EDISON INTERNATIONAL	9.55%	11.08%	15.73%	-0.98%	5.59%	0.585
EL PASO ELECTRIC CO	10.44%	10.20%	13.62%	8.06%	1.73%	0.166
ENTERGY CORP	9.30%	12.06%	15.57%	-6.98%	7.84%	0.843
FIRSTENERGY CORP	8.27%	6.66%	16.20%	2.41%	4.98%	0.602
IDACORP INC	9.07%	9.39%	10.06%	6.82%	1.06%	0.117
MGE ENERGY INC	11.09%	11.05%	12.18%	10.16%	0.69%	0.062
NEW JERSEY RESOURCES CORP	12.57%	12.99%	16.35%	3.95%	3.73%	0.297
NEXTERA ENERGY INC	12.41%	12.30%	14.03%	10.58%	0.94%	0.076
NORTHWEST NATURAL GAS CO	9.21%	8.55%	12.53%	6.88%	2.01%	0.218
NORTHWESTERN CORP	9.19%	9.38%	10.77%	6.46%	1.22%	0.133
OGE ENERGY CORP	12.14%	12.71%	14.53%	8.16%	1.83%	0.151
OTTER TAIL CORP	5.45%	7.24%	10.30%	-2.32%	5.08%	0.931
PG&E CORP	8.95%	8.53%	14.27%	5.36%	2.99%	0.334
PINNACLE WEST CAPITAL CORP	8.33%	9.15%	9.68%	2.06%	2.34%	0.280
PNM RESOURCES INC	3.13%	6.32%	11.24%	-16.41%	7.88%	2.514
PORTLAND GENERAL ELECTRIC CO	7.92%	8.01%	11.02%	5.77%	1.57%	0.198
PUBLIC SERVICE ENTRP GRP INC	13.73%	13.74%	18.34%	6.76%	3.56%	0.259
SCANA CORP	10.83%	10.43%	13.71%	9.95%	1.13%	0.104
SOUTH JERSEY INDUSTRIES INC	11.66%	11.19%	14.93%	9.22%	1.94%	0.167

SOUTHWEST GAS CORP	8.81%	9.02%	10.27%	5.87%	1.26%	0.143
WGL HOLDINGS INC	10.20%	10.88%	12.28%	6.40%	1.69%	0.165
XCEL ENERGY INC	9.66%	9.63%	10.20%	9.16%	0.42%	0.043
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**9.77%**	**10.18%**	14.09%	2.99%	3.36%	**0.413**
Median	**9.61%**	**9.83%**	13.44%	6.14%	2.17%	**0.236**
Max	**15.10%**	**14.56%**	32.14%	10.58%	13.59%	2.514
Min	**3.13%**	**6.32%**	9.32%	-19.99%	0.42%	0.043
StDev	**2.40%**	**2.10%**	4.78%	8.06%	2.97%	0.507

The ROE analysis above, similar to the analysis of CV(EBIT/Sales), suggests that the U.S. utilities possess greater risk than Alberta utilities. This is hardly surprising given that the U.S. sample is comprised of holding companies with various ownership structures and a variety of exposures to risks (including significant generation risks) to which Alberta transmission and distribution operating utilities are not – at least not to the same extent.

Clearly many of the utilities in the U.S. sample are distinct from Alberta operating utilities in terms of the risk they face. This is obvious from my discussion of beta estimation in Appendix B, which addresses Mr. Hevert's historical evidence of Canadian and U.S. utility beta estimates. Charts 22 and 23 of Mr. Hevert's evidence show that U.S. utility beta estimates have consistently exceeded those of Canadian utilities, with long-term averages of 0.51 and 0.43, which are 34.2% and 26.5% higher than the corresponding Canadian weekly and monthly average estimates of 0.38 and 0.34. In fact however, this difference in Canada-U.S. beta estimates understates the true difference in risk, since the estimated betas are "levered" betas (i.e., they do not adjust for differences in the leverage ratios of the companies used to estimate them). The reason this is misleading is because U.S. utilities display higher levered betas, despite the fact they should be expected to have lower leverage ratios on average (i.e., since U.S. utilities have higher allowed equity ratios). Hence, we would expect them to have lower betas than their Canadian counterparts if they had the same level of business risk. The opposite finding provides strong evidence that U.S. utilities possess *greater* business risk than Canadian utilities, since they have lower financial leverage (and hence lower financial risk) on average than Canadian utilities. Appendix B shows that the true *comparable* U.S. beta historical averages of 0.61 (monthly) and 0.72 (weekly) are almost double the comparable Canadian beta estimates of 0.34 and 0.38, after accounting for leverage differences.

Given such evidence, it is also not surprising that 17 of the 30 utilities included in Dr. Villadsen's U.S. Electric sample are rated in the BBB category (as well as 2 out of 9 utilities in her U.S. Gas sample). 14 of 25 utilities in Mr. Hevert's U.S. sample also fall in the BBB category, as do 3 of the 11 utilities in Mr. Coyne's U.S. sample. As mentioned, there is overlap in some of the firms in the utilities' experts' U.S. samples, and the net result is that 18 of the 32 firms examined in my U.S. sample in Tables 23 and 24 above have debt ratings in the BBB category. It is hardly surprising that my results above confirm that Alberta utilities possess lower risk than the U.S. utilities, as measured by lower volatility in operating income and ROE. As a result, I do not use U.S. samples in my analysis, since they are not good comparators in terms of the risks they possess.

4.3.4. Conclusions About Alberta Utilities' Risk Versus Comparables

The discussion above shows that U.S. holding companies are poor comparators for regulated Alberta utilities, since they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk. Given the significant issues with using U.S. comparables, I have used only Canadian utilities in both my CAPM and DCF analysis, while recognizing their limitations. In particular, while using Canadian utilities is better than using U.S. utilities, they are also imperfect comparators, since public information is generally only available for holding companies and not for operating companies. Given the comparability issues involved, I note that I focused on the use of averages, index betas and long-term average Canadian utility beta estimates in arriving at a final beta estimate. Similarly, I used averages across the utilities in my DCF analyses to try and mitigate potential comparability issues, and more importantly I use my market DCF estimates (which I consider to be more reliable) as a reasonableness check on the results.

The most important conclusion that arises from my analysis in Sections 4.1-4.3 is that regulated Alberta utilities possess very low business risk. My quantitative analysis in

Sections 4.2 and 4.3 confirms this fact, which supports Mr. Bell's conclusions and reflects the long-standing business risk assessment of Alberta utilities by debt rating agencies.

4.4. Financial Risk and Credit Metrics

Section 4.3 shows that Alberta utilities have earned ROEs at or above their allowed ROEs for the last 11 years – exceeding them by an annual average of 0.64% (weighted average of 0.97%). They have done so with very low volatility in these earned ROEs. These facts suggest that they possess low total risk, which is a function of both business risk and financial risk.

The allowed equity ratios ("**ERs**") in the 2016 GCOC Decision were 37% for all of the utilities, with the exception of the ER of 41% for AltaGas. Mr. Bell's evidence shows that the EBIT coverage ratio, the FFO coverage ratio and the FFO/Debt ratios associated with an ER of 37% and at the existing ROE of 8.5% would be 2.39, 3.58 and 12.00% respectively. These ratios exceed the AUC's thresholds of 2.0, 3.0 and 11.1%-14.3%, respectively, very comfortably. Appendix B of Mr. Bell's evidence further shows that the metrics for Alberta utilities would exceed the minimum AUC values if the ER was maintained at 37%, while the allowed ROE was reduced to 7.5% - with EBIT coverage of 2.23, FFO coverage of 3.45 and FFO/Debt of 11.44%.

Given my conclusions regarding the low risk possessed by Alberta utilities, the metric analysis above shows that the AUC can comfortably reduce the allowed ROE in combination with the existing equity ratio of 37%,[92] and maintain the financial integrity of the utilities.

4.5. Capital Structure Recommendation

The utilities' evidence argues that Alberta utilities possess similar risk to their U.S. and Canadian utility samples, but may in fact be higher. I strongly disagree with such statements for several reasons. First, my empirical analysis provides strong evidence that Alberta utilities have much less risk than the U.S. utilities groups presented in the utilities' evidence. This is consistent with the higher betas displayed by U.S. utilities historically, despite the fact

[92] This is also true for an ER of 36%, which is ENMAX's current allowed ER according to Mr. Coyne's evidence (i.e., refer to Exhibit 22570-X0131, page 113 or PDF 114).

they have lower leverage ratios. It is also consistent with the high proportion of utilities rated below A in the U.S. samples.

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk, it is not surprising that they have been able to generate ROEs above the allowed ROEs for the last 11 years consecutively, and that these earned ROEs have displayed low volatility. My analysis of the global, Canadian and Alberta economies suggests that economic and capital market conditions are stable and have improved since the time of the 2016 GCOC Proceeding. I recommend that the Commission maintain existing allowed equity ratios, in combination with my recommended reduction in the allowed ROE. My risk analysis suggests this is a reasonable approach, and the credit metric analysis provided by Mr. Bell supports this position.

5. ROEs AND CAPITAL STRUCTURE

One way to illustrate the relationship between ROE and equity ratios is to use the DuPont system for decomposing ROE into basic components. The standard 3-point decomposition formula breaks ROE into three financial ratios which are considered important by analysts examining company performance. These ratios are: the net income margin (net income dividend by sales, or "**NI/S**"); the asset turnover ratio (total sales divided by total assets, or "**S/TA**"); and, the leverage ratio (total assets divided by total equity, or "**A/E**"). Since ROE is defined as net income divided by total equity (or "**NI/E**"), we can see the multiplying the three ratios above by one another leaves us with NI/E or ROE. This equation is presented below:

$$ROE = NI/S \times S/A \times A/E$$

Since the product of the first two terms reduces to NI/A, or the return on assets ("**ROA**"), it is also common to observe that ROE = ROA × A/E, which is convenient for my discussion.

I begin by noting that a higher leverage ratio (A/E) implies a lower equity ratio, and vice-versa. Non-regulated firms will typically try to choose a leverage ratio that generates higher ROEs, while recognizing that higher leverage ratios generate additional financial risk, as reflected in greater volatility in ROEs, all else being equal. However, regulated utilities earn higher NI if they have a higher ER (i.e., lower A/E) since they earn the allowed ROE on this higher equity dollar figure. Of course they should also earn higher ROEs if they are awarded higher allowed ROEs. So regulated utilities prefer both higher allowed ROEs and higher ERs. Not only do the utilities earn higher net income if they have higher allowed ERs, it also reduces their financial risk and the associated volatility in ROEs, all else being equal. Of course, this additional net income and reduction in earnings volatility comes at the expense of consumers, as reflected in their rates.

I would note that my analysis in Section 3 shows that Alberta utilities have low business risk, as reflected by volatility in operating income, and that they also maintain low total risk as reflected in both their ability to earned allowed ROEs and the low volatility in those earned ROEs. As Mr. Stauft mentioned in his evidence in the 2016 GCOC Proceeding, the holding companies of many of the Alberta regulated utilities maintain equity ratios at the holding company level that are lower than at the regulated operating company level.[93] This makes sense to me since they can increase their earned ROEs by doing so (as long as ROA remains positive), as long as they are comfortable with the additional volatility in ROE. Given the low volatility in both operating income and earned ROEs that I have noted, it seems reasonable that additional volatility is not problematic.

The discussion above supports the notion that the AUC approach of setting one allowable ROE for utilities and then adjusting the allowed ERs to vary according to risk levels relative to the “average” utility is a logical approach. The granting of higher ERs to utilities deemed to have greater business risk appropriately reduces the financial risk of such utilities. Since total risk is a function of both business and financial risk, such a process is a useful mechanism for controlling total risk.

This concludes my testimony.

[93] See Exhibit 20622-X0303, Evidence of Mark Stauft, pages 9-12. For example, Mr. Stauft noted at that time that Canadian Utilities Ltd. had an equity ratio of 32%, Fortis Inc. had an equity ratio of 36%, and AltaLink Investments had a consolidated common equity ratio of about 27%.

Attachment 4: Alberta GCOC proceedings in 2019-20 (AUC Proceeding ID 24110)

ALBERTA UTILITIES COMMISSION

2021 GENERIC COST OF CAPITAL

PROCEEDING ID #24110

EVIDENCE OF DR. SEAN CLEARY, CFA,
BMO PROFESSOR OF FINANCE

Submitted on behalf of:

The Office of the Utilities Consumer Advocate

January 20, 2020

TABLE OF CONTENTS

1. INTRODUCTION

1.1. Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen’s University. I am currently the BMO Professor of Finance at the Smith School of Business at Queen’s University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta (the **“UCA”**) on several occasions including generic cost of capital (“**GCOC**”) proceedings in 2013-2014 (Proceeding ID 2191), 2015-2016 (Proceeding ID 20622), and 2018 (Proceeding ID 22570), as well as the generic regulated rate option proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan proceeding (Proceeding ID 22357) in 2017. I also prepared evidence on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016, and in 2018.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of 30 publications. My work has been cited over 3,700 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of equity issues. I have authored or co-authored 14 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Appendix A to my evidence.

1.2. Purpose of Testimony

With respect to the 2021 GCOC Proceeding (Proceeding 24110) in Alberta, the UCA has requested that I provide recommendations regarding the appropriate return on equity (“**ROE**”) and equity ratios for Alberta utilities, and comment as to whether or not an annual

ROE formula should be adopted, and if so what that formula would look like. I acknowledge that I have a duty to provide opinion evidence to the Alberta Utilities Commission (the "**Commission**" or "**AUC**") that is fair, objective and nonpartisan.

1.3. Summary of ROE Estimates

Section 2 shows that economic and capital market conditions remain solid, similar to those prevailing at the time of the 2018 GCOC Proceeding (Proceeding 22570), except that long-term government yields and long-term A-rated utility yields have both declined by approximately 50 basis points (bp) since that time to 1.7% and 3.0% respectively. Both Canada and Alberta are expected to experience moderate but solid GDP growth going forward. A-rated bond yield spreads remain around the same level (1.3%) as they were during the 2018 Proceeding, and well below spreads of around 2% that existed when evidence was prepared during the 2016 Proceeding. Stock market volatility remains well below long-term averages and well below 2016 levels, and by all indications, both bond and stock markets remain healthy. In other words, economic and capital market conditions are as solid today as they were in 2018, much improved from 2016, and far removed from those existing at the peak of the 2008-2009 financial crisis. Further, the cost of capital to Canadian utilities has declined since 2018, as reflected by the 0.5% decline in both the risk-free rate and in long-term utility borrowing costs, the later of which is approximately 1% below 2016 levels. All of this is positive for utilities; although it should be remembered that mature, regulated utilities operating in established territories are not influenced by economic cyclicality to the extent of traditional businesses. My evidence confirms this is true for Alberta utilities.

Several approaches were used to estimate the appropriate generic ROE for Alberta utilities including the Capital Asset Pricing Model ("**CAPM**"), Discounted Cash Flow ("**DCF**") and Bond Yield Plus Risk Premium ("**BYPRP**") models. Based on an equal weighting of these three approaches, I determined the following best estimates for an appropriate ROE:

Year	CAPM (1/3rd)	DCF (1/3rd)	BYPRP (1/3rd)	Best Estimate
2021-2022	5.0%	6.9%	6.0%	**6.0%**

The details of all estimates are provided herein, as is the reason for choosing an equal weighting scheme.

This estimate is 30 bp below my 2018 estimate, which is consistent with a reduction in the utilities' cost of capital since the risk-free rate and utility bond yields have both declined 50 bp since that time. It is a very reasonable estimate when compared to current expectations of market professionals for long-term overall stock market returns in the range of 5-9% (with a best estimate of 7.0%), when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% inflation expectations and long-term real growth expectations in the 1.7-2.0% range. It is also consistent with our current low interest rate environment, which is not expected to change materially over the forecast period.

1.4. Summary of Comments on Capital Structure

My analysis shows that Alberta utilities possess low risk as shown by their consistent "low business risk" ratings, their low earnings volatility, and most importantly, their ability to generate earned ROEs above the allowed ROEs for the last 13 years, exceeding the allowed ROE by an annual average (weighted average) of 0.72% (1.05%) over the 2005-2018 period. My analysis also shows that these earned ROEs displayed very low volatility, indicating low total risk.

Combining this risk analysis with my positive economic and capital market outlook, I am recommending no change in allowed equity ratios, but rather emphasize the impetus for a reduction in the allowed ROE. My analysis suggests these recommendations are reasonable, and the credit metric analysis provided by Mr. Bell supports this recommendation.

2. THE ECONOMY AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE

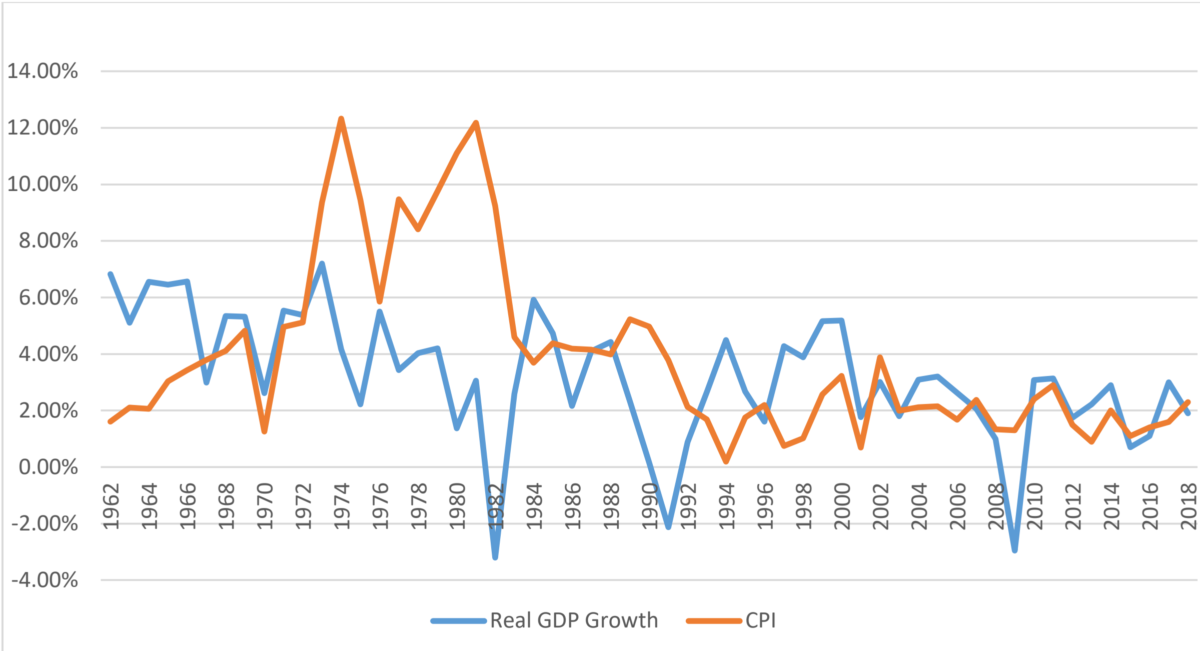
2.1. The Past and Present

2.1.1. Historical Evidence

Figure 1 below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index ("**CPI**") over the 1962 to 2018 period. The graph shows that real GDP growth has generally been in the 2-6% range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average GDP growth over the entire period was 3.2% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.5% (median 2.7%) over the 1992 to 2018 period, which is more in line with forecasts for future growth in the 2% range. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from Figure 1, and also as measured by the standard deviation reported in Table 1. The working papers for Figure 1 and Table 1, below, are appended as Exhibit A to my evidence.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2018)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2018)

	1962-2018 (%)		1992-2018 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.18	3.89	2.45	1.82
Geometric Average	3.16	3.84	2.44	1.82
Median	3.06	2.90	2.66	1.75
Max	7.20	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.21	3.08	1.62	0.82

Data Source: Statistics Canada.

The 1962-2018 stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average CPI of 1.82% (median 1.75%). CPI growth has also been very stable during this latter period, which is obvious from Figure 1, and also by the huge decline in standard deviation from 3.1% over the entire 1962-2018 period to 0.8% since 1991. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2. Changes since the 2018 Decision

In Decision 22570-D01-2018 (the **"2018 GCOC Decision"**), the Commission noted the following prevailing economic and market conditions:

- The 30-year GOC bond yields have not increased to the same extent as the 10-year GOC bond yields and the spread between them has contracted to 17 bps at the time of the hearing for this proceeding, compared to the long-run historical average of approximately 50 bps.

- While the 30-year GOC bond yields have increased slightly since the close of record for the 2016 GCOC proceeding, when considering their movement over the last three years, they are generally unchanged.

- The 30-year utility bond yields have stayed in the range of those present during the 2016 GCOC proceeding. This has had the effect that credit spreads between 30-year utility bond yields and 30-year GOC bond yields have decreased from 179 bps at the time of the hearing for the 2016 GCOC proceeding to 130 bps at the time of the hearing for this proceeding.[1]

The Commission also noted that a reduction in yield spreads and decline in volatility indexes such as the VIX and VIXC indicated a reduction in investor uncertainty relative to 2016 levels.

The Commission went on to provide the following summary statement regarding economic and capital market conditions:

> In conclusion, the Commission finds that the global economic and Canadian capital market conditions have improved since the 2016 GCOC proceeding, and are far removed from the 2008-2009 financial crisis. In particular, the Commission observes that there has been global

[1] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 43, para. 199.

> and national economic growth, reduced market volatility, a modest increase in the 30-year GOC bond yield and a compression in credit spreads.[2]

Further, with respect to Canadian GDP growth and expected inflation, in the **2018 GCOC Decision**, the Commission stated:

> Looking forward, the Commission was presented with forecasts of Canadian economic growth, including projections by the Bank of Canada, that indicate slowing economic growth, with rates of 2.1 per cent in 2018 and 1.5 per cent in 2019. Inflation is broadly expected to be near the Bank of Canada's target rate of two per cent over this same period.[3]

In fact, real GDP growth turned out to be in line with these forecasts – at 1.9% in 2018, and at 1.5% in 2019 (as estimated in the Bank of Canada's October 2019 *Monetary Policy Report* ("**MPR**"), appended as Exhibit AA to this evidence). Inflation materialized at 2.3% in 2018 and was estimated at 2.0% in 2019 in the Bank's October 2019 MPR.

As a result of this strength in the Canadian economy during 2018, the Bank increased its overnight lending rate by 0.25% three times in January, July and October, leaving it at 1.75%, where it has now sat for over a year. In contrast, at the other end of the yield curve, Canadian long-term government bond yields decreased steadily through 2019, with 30-year yields sitting at 1.67% as of December 27, 2019 – a full 52 bp below their December 2017 levels (i.e., 2.19%). The possibility of simultaneous increases in short-term rates and decreases in long-term rates was noted by myself during the 2018 Proceeding, as referenced in the 2018 GCOC Decision:

> As Dr. Cleary pointed out, central bank policy interest rates only tend to affect the "short end" of the yield curve (Figure 1). The Commission observes that the yield curve is "flattening," as in, the "long end" of the yield curve, or the yield on 30-year GOC bonds has not increased to the same degree as short-term interest rates since the 2016 GCOC proceeding (figures 1 and 2).[4]

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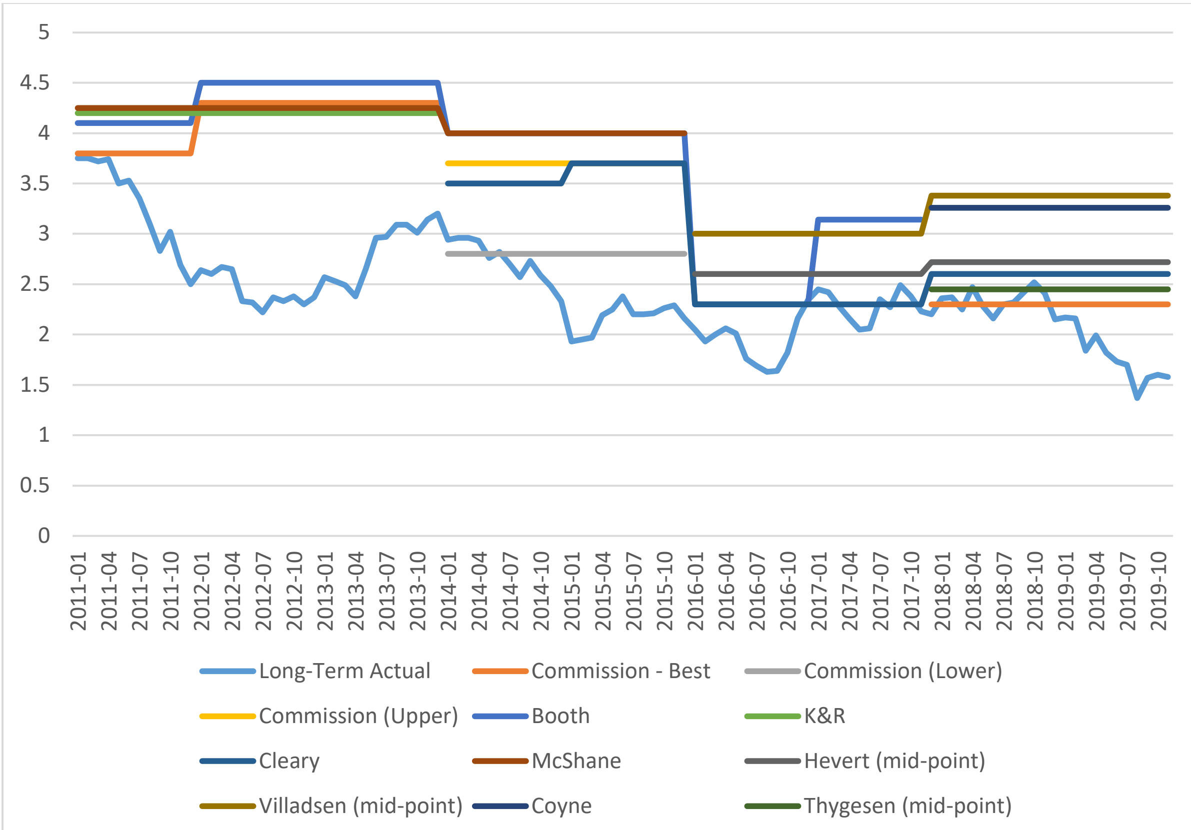
[2] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 45, para. 206.
[3] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 42, para. 194.
[4] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 43, para. 198.

During the 2016 and 2018 GCOC Proceedings, I noted that Consensus forecasts had consistently been too high in previous decisions, and consistent with the approach used by the Commission in its 2013 GCOC Decision (Decision 2191-D01-2015), I used the actual prevailing long-term yield at the time as a lower bound, and used the Consensus-based estimate as my upper bound. I then used the mid-point of these figures (2.3% in 2016 and 2.6% in 2018) as my base case long-term Canada government bond yield estimate for the test period. My 2016 estimate turned out to be very appropriate as the average 30-year government yield from January 1, 2017- November 15, 2017 was 2.29%; however, my 2.6% estimate in 2018 proved to be too high, as the average 30-year government yield from December 2017-November 2019 was 2.07%. This is because my estimate was biased upwards by the influence of Consensus estimates which turned out to be too high, just as they had been during the time periods involved during previous proceedings. This is precisely why it is beneficial to incorporate existing rates as a base – i.e., as a floor when rates are expected to increase, or as ceilings when rates are expected to decrease, or even as a best estimate, as the Commission did in 2018. In other words, forecasters are often wrong, while existing rates offer the benefit of a starting point that reflects actual yields (i.e., yields that investors can actually achieve today), rather than forecasts which may or may not materialize. This is obvious when we look at Figure 2, produced below, which reports the estimates provided by all experts and the Commission in the 2011, 2013, 2016 and 2018 GCOC Proceedings, which were all well above the actual long-term government bond yields that materialized, with the exception of my 2016 forecasts which were close. It is worthy of note that the Commission used the existing government yield of 2.3% in 2018, which was the most accurate estimate, followed by Mr. Thygesen at 2.45%, then myself at 2.6%, and Mr. Hevert at 2.72%. Similar to previous proceedings, the estimates that relied entirely on Consensus forecasts and ignored the level of prevailing rates at that time (i.e., Dr. Villadsen at 3.38% and Mr. Coyne at 3.26%), were much further off the mark. The working papers for Figure 2 are appended as Exhibit B to my evidence.

FIGURE 2

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2011-2019)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

The fact that using existing rates has worked better than using Consensus forecasts is well-supported by academic studies. For example, a study by Hafer and Hein (1989)[5] shows that economic forecasters do not perform any better than using futures rates, and perform WORSE than naïve forecasts (i.e., simply using the existing rates). In particular, this study shows that naïve forecasts perform the best under one of their measures of accuracy, while using interest rate futures performs best under their other measure of forecasting accuracy. Economic forecasters, on the other hand, perform worst under both measures of forecast accuracy. Similarly, a 2005 study by Mitchell and Pearce (2007)[6] examined the six-month-ahead forecasts of Treasury bill and Treasury bond rates from 1982 to 2002. This study found that: "Most economists' forecast accuracy is statistically indistinguishable from a random walk model in forecasting the Treasury bill rate, but many are significantly worse in

[5] This article is appended to my evidence as Exhibit AB.
[6] This article is appended to my evidence as Exhibit AC.

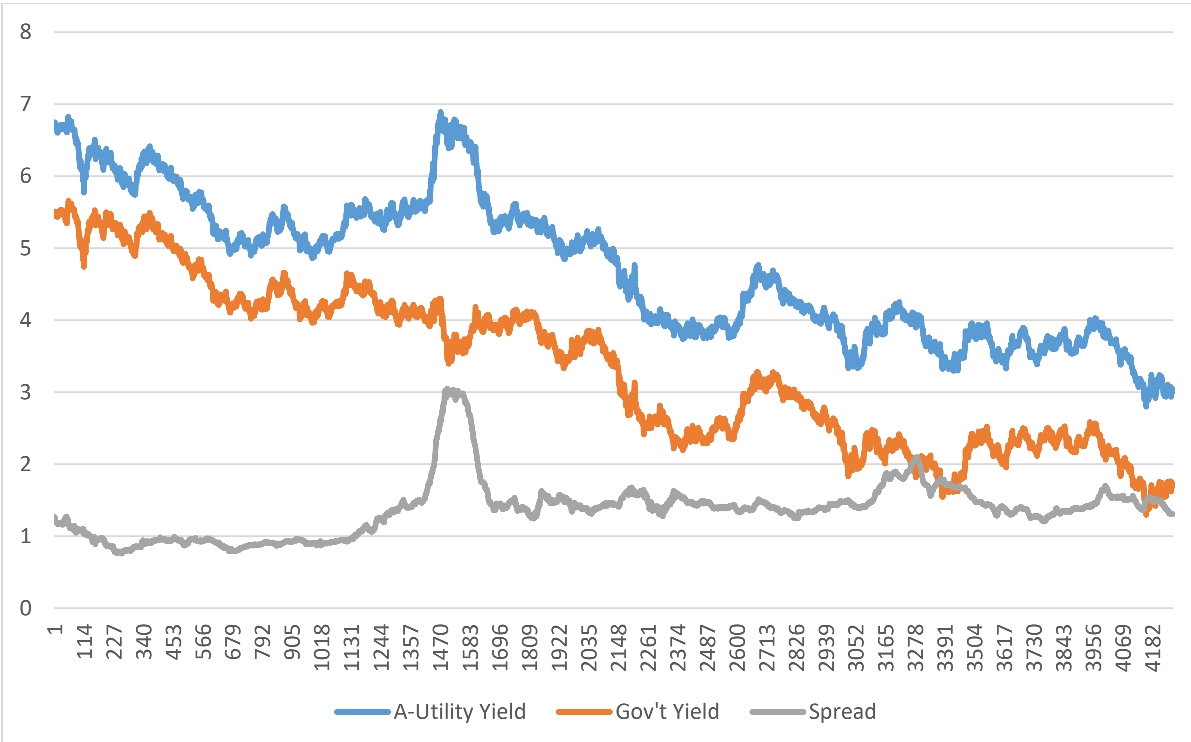
forecasting the Treasury bond rate and the exchange rate."[7] Yet another study by Spiwoks, Bedke and Hein (2008)[8] examined 10-year US government bond yield and three-month US Treasury bill rate forecast accuracy for the 1989 to 2004 period. They found that "sign accuracy is significantly better than random walk forecasts in only a very few of the forecast time series." This indicates forecasters are not very successful in simply forecasting the direction of future interest rates. Not surprisingly, they further find that "the information content of most of the forecast time series is lower than that of the naïve forecasts."

It is important to acknowledge that the total cost of borrowing to utilities is a function of both the level of government yields and the yield spreads on utility bonds, as I have noted in my previous evidence. Figure 3 shows that since the time of my 2018 evidence, long-term government yields have declined approximately 50 bp to 1.7%, while yield spreads have remained at about 130 bp. The net result is a decrease in A-rated Utility bond yields to about 3%, approximately 50 bp lower than when I prepared my evidence in the 2018 GCOC Proceeding, and 100 bp lower than when I prepared my 2016 GCOC evidence. In particular, as of January 13, 2020, the A-rated utility yield was 3.02% and the long-term Canada bond yield was 1.71%. The working papers for Figure 3 are appended as Exhibit C to my evidence.

[7] The random walk model is equivalent to using naïve forecasts, as defined above.
[8] This article is appended to my evidence as Exhibit AD.

FIGURE 3

A-UTILITY YIELDS (January 1, 2003-January 13, 2020)



Source: Bloomberg.

Regardless of whether one focuses on yield spreads, on underlying government bond yields, or on both (as should be the case), it is obvious that the cost of long-term borrowing for A-rated Canadian utilities, as measured by long-term bond yields, are near all-time lows, and are 50bp below the 2018 levels. This implies that the cost of equity for A-rated utilities is also low in both absolute and relative terms, since a company's cost of equity is linked to its cost of debt.[9]

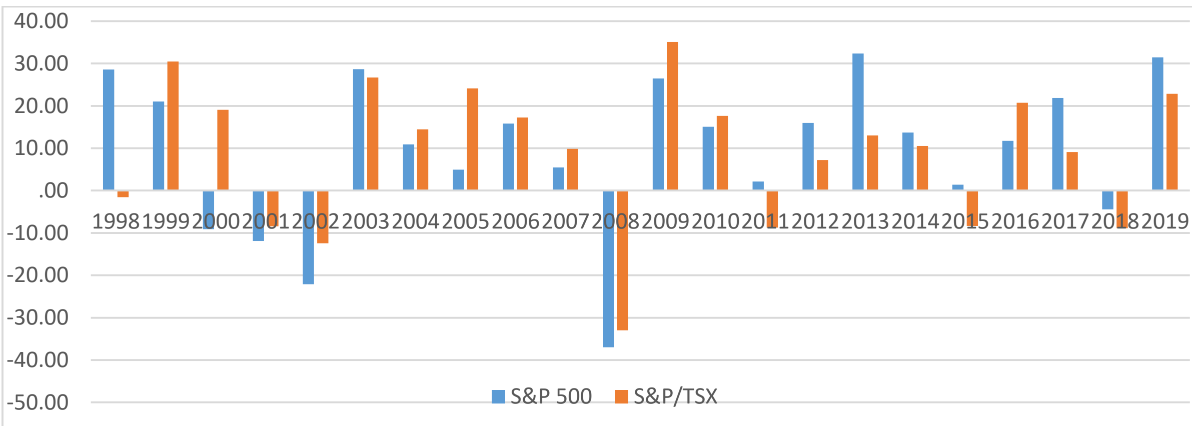
The Canadian stock market had an excellent year in 2019, providing a total return of 22.8%, while U.S. markets did even better with a return of 31.5%. Figure 4 provides the average annual total stock returns for Canada and the U.S. over the 1998-2019 period. Over this period, stocks in Canada provided an average return of 9.2% (geometric mean of 7.6%), while U.S. stocks provided an average return of 8.9% (geometric mean of 7.6%). These

[9] For example, this link is very clear in the widely used BYPRP approach, which will be discussed in detail in Section 3.4.

figures are consistent with long-term "real" stock returns in the 6% to 7% range, and current market expectations (both of which are discussed in Section 3.2.3) that are based on lower inflation expectations over more recent periods, as monetary authorities around the globe have strived to maintain inflation levels in the area of 2%. The working papers for Figure 4 have been appended as Exhibit D to my evidence.

FIGURE 4

STOCK MARKET RETURNS - (1998-2019)



Source: Bloomberg

The trailing price-earnings ("**P/E**") ratio for the S&P/TSX Composite Index stood at 17.7 on January 15, 2020, while the P/E ratio for the U.S. S&P 500 Index was 22.0 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below 15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 17 to 22 range in Canada and the U.S. are in familiar territory; albeit slightly elevated in the case of the U.S. As of the same date, dividend yields were 1.8% in the U.S. and 3.0% in Canada, also within typical ranges.

The implied volatility indexes in Canada and the U.S. have averaged in the 16-20 range through time.[10] The Canadian and U.S. VIX indices stood at 12.7 and 13.4 respectively as of December 27, 2019, indicating well below normal volatility in both Canada and the U.S. The

[10] According to Mr. Hevert's 2018 evidence, the U.S. index had averaged 19.5 since 1990, while the current Canadian index had averaged 16.6 since its inception in 2009.

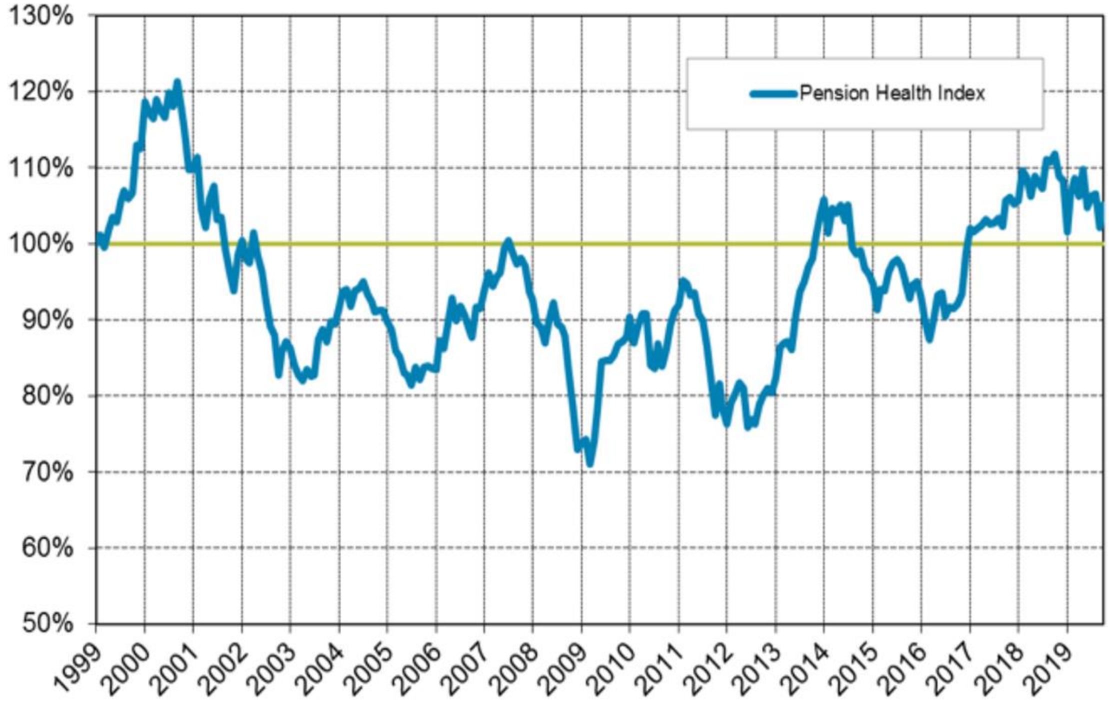
current levels are dramatically lower than those that existed at the start of the 2016 GCOC Proceeding and are well below long-term averages.

Finally, pension fund health is a closely watched and important financial health indicator. Poor stock returns during the 2007-09 crisis, combined with extremely low levels of interest rates, hit the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall Canadian pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 5 depicts the value of this index over the 1999 to Q3-2019 period. The index ended September of 2019 at 105%, up from 102% at the start of 2019, just 1% below the level of 106% at which it sat in January of 2018 when I prepared my evidence for the 2018 GCOC Proceeding.[11] This level is comfortably above 100%, and is well above the all-time low of around 70% in early 2009. Hence, this measure of financial stability indicates stable and solid market conditions, which are nowhere near crisis levels.

[11] As of December 31, 2019, the index stood at 112%. Source: https://www.theglobeandmail.com/business/article-soaring-equity-markets-fuelled-pension-plan-growth-in-2019-despite-low/, January 3, 2020.

FIGURE 5

MERCER PENSION HEALTH INDEX - (1999-Q3, 2019)



Source: https://www.mercer.ca/content/mercer/north-america/ca/en/newsroom/defined-benefit-plans-drop-slightly-in-q3.html December 26, 2019.

2.2. The Future

2.2.1. Global Economic Activity

The global economy is expected to grow at solid rates in the 2.5 to 3.1% range during 2019 and 2020. For example, Table 2 shows the December 2019 Consensus forecasts[12] for average global real GDP growth figures of [redacted] while the Bank of Canada's October 2019 MPR estimates were 2.9% and 3.1% respectively. Table 2 shows that this global growth is expected, despite subdued yet steady U.S. growth of [redacted] and [redacted] and with slow growth expected in the Euro zone at rates of [redacted] and [redacted] Meanwhile, according to the Bank's MPR, Chinese GDP growth is expected at around 6% in 2019 and 2020.

[12] Appended to my evidence as Exhibit AE.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2019-2020)

Real GDP Growth (%)	2019		2020	
	Consensus	**Bank of Canada**	**Consensus**	**Bank of Canada**
World	[redacted]	2.9	[redacted]	3.1
U.S.	[redacted]	2.3	[redacted]	1.9
Euro Zone	[redacted]	1.1	[redacted]	1.0
China		6.1		5.9

Source: Consensus Economics Inc. (December 2019) and Bank of Canada MPR (October 2019).

The Bank of Canada discusses several factors affecting global economic growth in its October 2019 MPR. The Bank notes the impact of global trade tensions, which continue to impact all sectors, particularly business investment and the manufacturing sector. They also note that despite these tensions, unemployment remains low in most developed economies, while central banks have eased monetary conditions, providing financial conditions that have supported growth.

2.2.2. Canada's Outlook

The Bank of Canada noted in its October 2019 MPR that Canadian economic growth had been moderate during the preceding year. A strong labour market and a recent rebound in housing supported this growth, while growth was dampened by global trade issues, which impacted both investment and exports. Overall, the Bank forecast real GDP growth of 1.5% for 2019.

Going forward, the Bank expects improved real GDP growth during 2020 (1.7%) and 2021 (1.8%). This growth will be supported by growth in business investment and exports, despite the continued presence of global trade uncertainties, which have contributed to tempered growth projections. Stable consumer spending, based on support from solid labour markets, will also contribute to economic growth. [redacted]

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2019-2021)

	2019	2020	2021
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
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[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
Bank of Canada (Oct 2019)	**1.5**	**1.7**	**1.8**

Source: Consensus Economics Inc. (December 2019) and Bank of Canada MPR (October 2019).

Based on the discussion above, the Bank predicts that inflation would remain at the mid-point of its target range (i.e., 2.0%) in 2019, and would remain near this level at 1.8% in 2020 and at 2.0% in 2021. [redacted]

TABLE 4

CPI FORECASTS – CANADA (2019-2021)

	2019	**2020**	**2021**
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
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[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
Bank of Canada (Oct 2019)	**2.0**	**1.8**	**2.0**

Source: Consensus Economics Inc. (December 2019) and Bank of Canada MPR (October 2019).

Of course, there are always uncertainties associated with economic projections. The Bank noted that global trade uncertainties remain the most important risk. If these uncertainties disappeared or dissipated, they would expect stronger than forecast economic growth. The Bank also identified several other risks to their inflation outlook, and suggested that aside from trade uncertainty these risks "to the projected path for Canadian inflations are roughly balanced." The other noted risks are: (1) a tightening of global monetary and financial conditions; (2) stronger than expected consumption in Canada; (3) stronger residential investment and rising household vulnerabilities; (4) weaker growth in emerging market economies; and, (5) global disinflation.

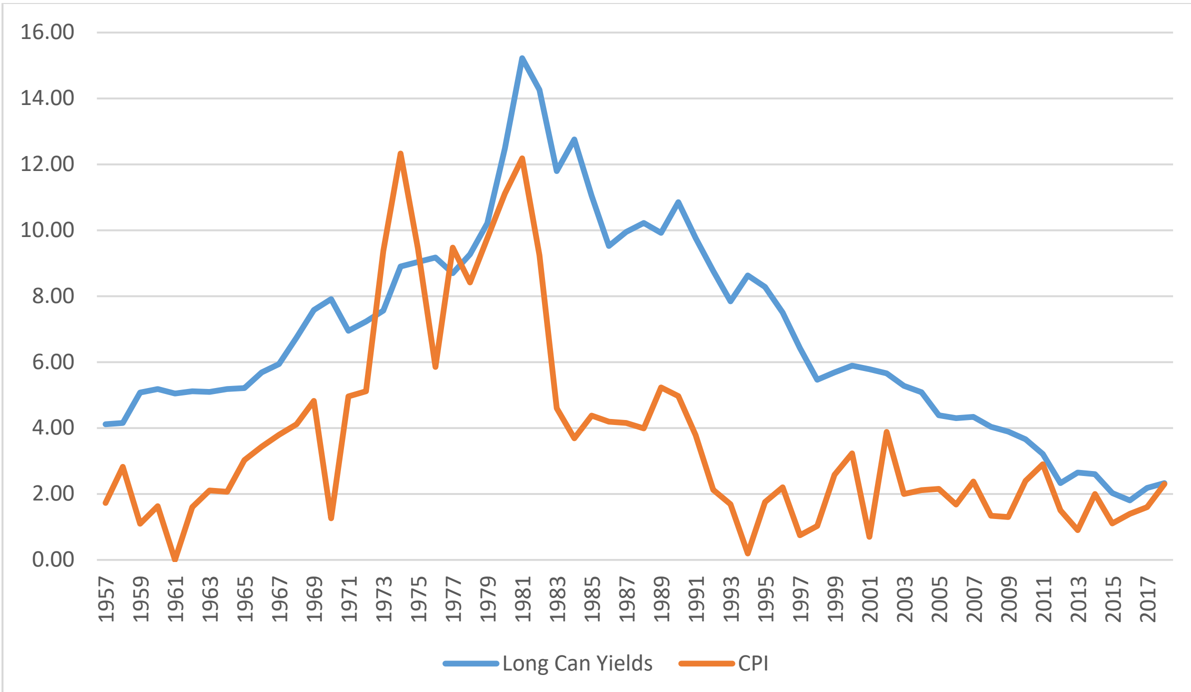
2.3. Capital Market Conditions and Expectations

2.3.1. Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 6 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation. Of course, yields are determined based on “expected” inflation, and we can see a few years in the 1970s where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since 1991 is obvious from the graph, with inflation hovering around the 2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 3.93%, with inflation averaging 1.93%. Not only have long-term Canada bond yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005, or 4% since 2008.

FIGURE 6

BOND YIELDS AND INFLATION – CANADA (1957-2018)

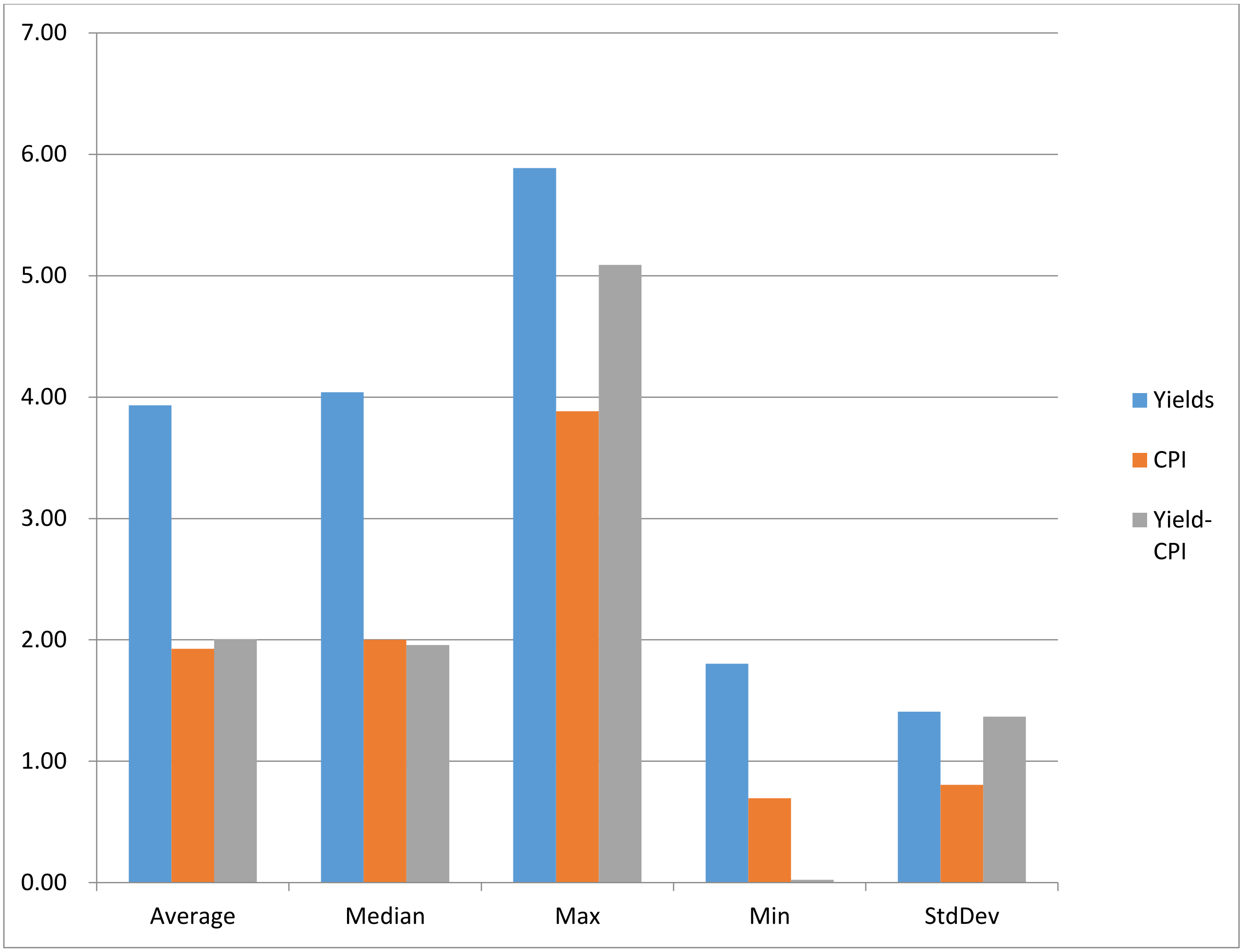


Data Source: CANSIM database.

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 6. This can also be seen in the standard deviations reported in Figure 7, which reports summary statistics for the 1998 to 2018 period. For example, the standard deviation of the yields was 1.41% over this period, versus 3.13% over 1957-2018. Figure 7 also shows that the difference between yields and inflation averaged 2.01% over the period, with a standard deviation of 1.37%. Clearly, yields remain low today, but they are not forecasted to increase during the test period. While they may do so in the medium to long-term, it is reasonable to assume this would occur at a gradual pace, and it may take quite some time (i.e., more than 5 years) to reach 4% levels, if in fact they ever do. The working papers for Figure 6 and Figure 7 are appended as Exhibit E to my evidence.

FIGURE 7

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2018)



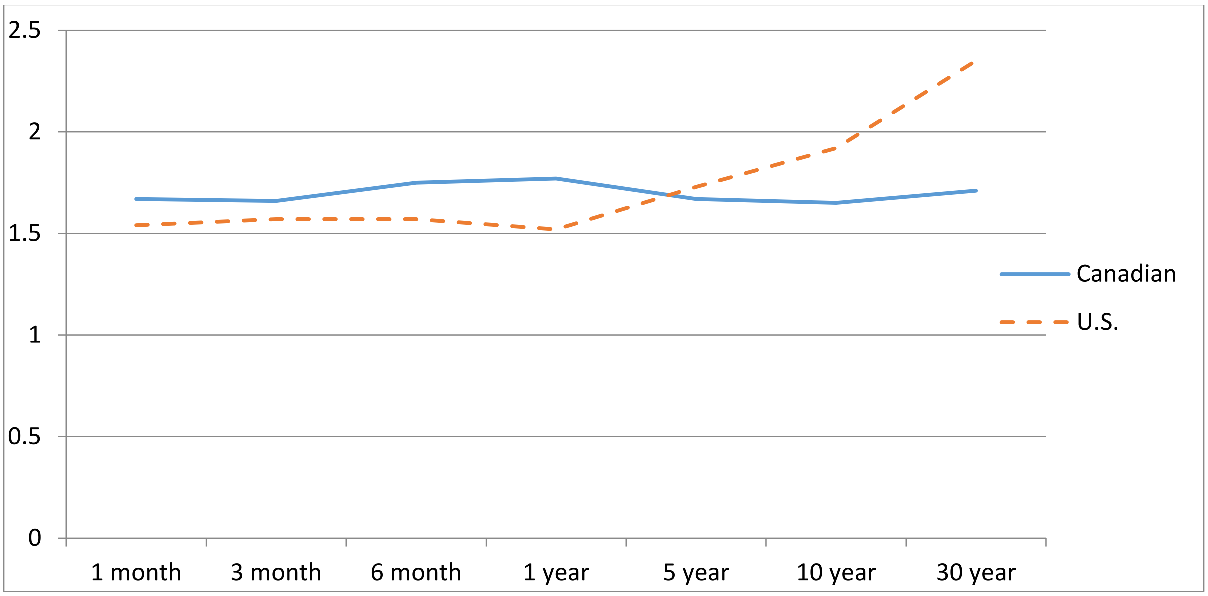
Data Source: CANSIM database.

Figure 8 below depicts the yield curves for Canada and the U.S. as of December 19, 2019. We can see that short-term U.S. rates were below Canadian rates, but the opposite is true for 5 year rates and longer. For debt that matures within a year, U.S. yields were between 1.52% and 1.57%, while in Canada they were between 1.67% and 1.77%. At the long end of the yield curve, we see 5-year, 10-year and 30-year U.S. rates of 1.73%, 1.92% and 2.35%, which exceed their Canadian counterparts of 1.67%, 1.65% and 1.71% by 6 bp, 27 bp, and 64 bp respectively. According to the 10-year government yield forecasts for Canada and the U.S. from Consensus forecasts (December 2019), the spread between 10-year U.S. and Canadian rates are expected to [redacted]

[redacted] The working papers for Figure 8 are appended as Exhibit F to my evidence.

FIGURE 8

YIELD CURVES – CANADA AND THE U.S. (DECEMBER 19, 2019)



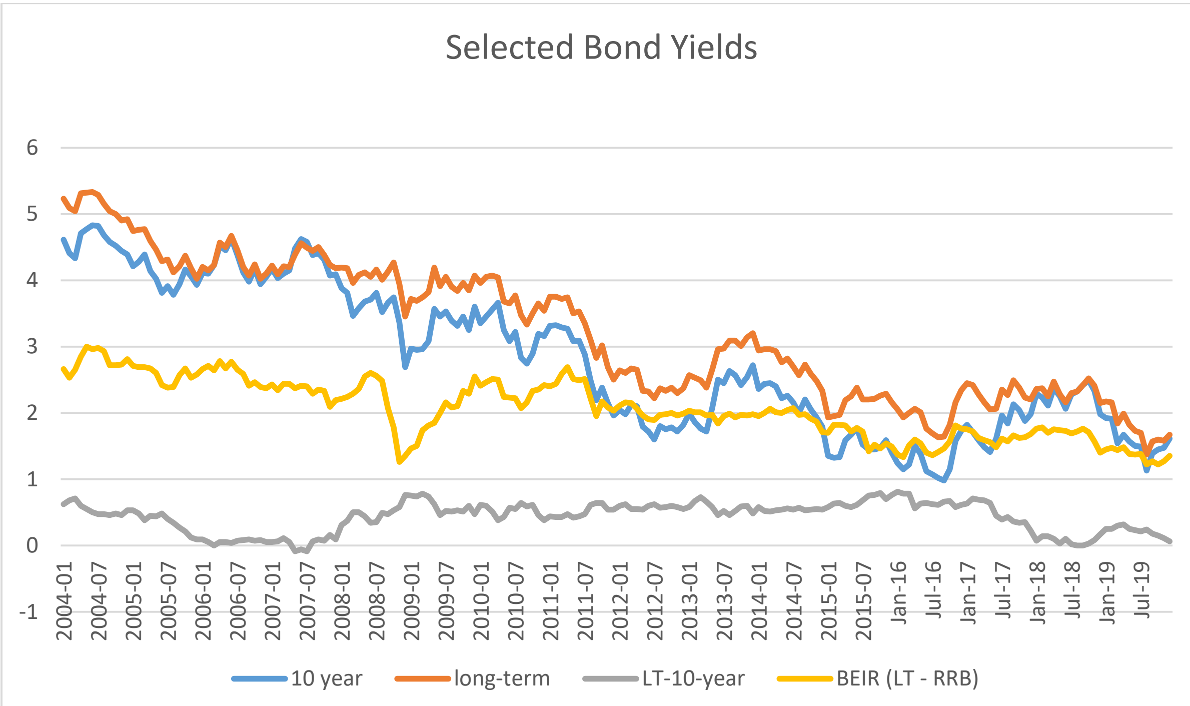
Sources: U.S. Data - https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield. Canadian data –Bank of Canada website. December 20, 2019.

2.3.2. Interest Rate Levels

Figure 9 shows 10-year and long-term bond yields in Canada over the last 16 years, which have moved in tandem for the most part, with a correlation coefficient of 0.98 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.43% (0.50%) over the entire period. It is obvious from Figure 9 that this spread has narrowed considerably during 2018-19, averaging 0.14% over these two years, and sitting at 0.06% at the end of December 2019, with long-term rates of 1.67% and 10-year rates of 1.61%. Figure 9 also shows the break-even inflation rate ("**BEIR**"), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR is often viewed as an indicator of future inflation rates. This rate remained within the Bank of Canada's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.22% in August 2019, and averaging 2.05% overall, slightly above the Bank's target. It sat at 1.35% at the end of December 2019, 45 basis points below the Bank's CPI forecast of 1.8% for 2020, and [redacted] The working papers for Figure 9 are appended as Exhibit G to my evidence.

FIGURE 9

SELECTED BOND YIELDS – CANADA (January 2004-December 2019)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

The consensus view of most economists as of December 2019 can be seen in Table 5, which reports Consensus forecasts for Government of Canada 10-year bond yields. The forecasts for 10-year Canada bond yields were [redacted] as of the end of March 2020 and [redacted] for the end of December 2020 [redacted]

[redacted]

[redacted] Considering these possibilities for long-term to 10-year yield spreads over the next year, a mid-point estimate [redacted] for long-term rate forecasts seems reasonable; although [redacted] one could also make the case that using the [redacted] is reasonable as well.

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2020)

10-Year Canada Yields	Mar-20	Dec-20
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Source: Consensus Economics Inc. (December 2019).

2.3.3. Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 6 reports summary statistics for Canadian capital markets over the 1938 to 2019 period. The working papers for Table 6 are appended as Exhibit H to my evidence.

TABLE 6

CAPITAL MARKET SUMMARY STATISTICS – (1938-2019)

1938-2019 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (CAD)
Average	3.57	11.05	6.43	4.58	12.81
Median	2.65	11.05	4.14	3.73	12.97
Std. Dev.	3.43	16.36	8.93	4.20	17.12
Geo. Mean	3.52	9.81	6.08	4.49	11.48

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM.

The long-term average return in the Canadian stock market over this period was 11.1%, with a geometric mean of 9.8%. This occurred over a period in which inflation averaged 3.6% (geometric mean of 3.5%) and real GDP growth was higher than it has been recently. This implies "real" returns of approximately 7.5% (6.3%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.3% to 9.5% going forward. These numbers are consistent with, but are higher than, most current estimates of expected stock returns going forward by market professionals, as shown in Table 6 and as discussed in Section 3.2.3.

2.4. The Alberta Economy

The Conference Board of Canada ("**CB**") 2019 Autumn Provincial Outlook, appended as Exhibit AF to my evidence, estimated that GDP growth in Alberta during 2019 would be slightly above zero at +0.2%. The CB predicts that Alberta will shake off a sluggish 2019 and be one of only two provinces (along with B.C.) to experience real growth in excess of 2% (at 2.4%) during 2020. The CB forecasts Alberta GDP growth of 3.1% in 2021. Much of this growth will be driven by rebound in business investment in the energy sector, in response to the Trans Mountain Expansion project, as well as other factors that should reduce congestion relief.

The CB forecasts Alberta's long-term real GDP growth and inflation over 2021-2040 would both average around 2%, according to its 2019 Provincial Outlook Long-Term Economic Forecast, appended as Exhibit AG to my evidence. This growth will be driven by steady growth in business investment, household consumption and real exports.

3. ROE CALCULATIONS

3.1 Some Notes on Allowed ROEs

In the 2018 GCOC Proceeding, I noted that allowed ROEs have not declined adequately in response to the reduction in the cost of capital that utilities' have experienced, as long-term government bond yields (RF) and A-rated utility bond yields have declined significantly over the last two decades. Figure 10 shows that since 2004, both RF and A-rated utility yields have declined markedly, while the allowed ROEs have declined much less so over this period. As a result, the spreads between allowed ROEs and these measures, both of which directly affect the utilities' cost of capital, have increased dramatically though the years. Figure 11 depicts these ROE-RF and ROE-A yield "spreads," both of which have increased dramatically throughout this period.[13] For example, in January 2004, the allowed ROE for Alberta utilities was 9.6%, at a time when 30-year government yields (RF) were 5.3% and A-rated utility yields were 6.1%. So, the spreads between the ROE and RF was **4.3%**, and between ROE and A yields was **3.5%**. As of January 13, 2020, the allowed ROE was 1.1% lower than in 2004 at 8.5%, while RF was 3.6% lower at 1.7%, and A yields were 3.1% lower at 3.0%. As a result the ROE-RF spread was 2.5% higher at **6.8%** (a 58% increase), while the ROE-A yield spread was 2% higher at **5.5%** (a 57% increase). The average ROE-RF spread during the January 2004-January 2020 period was 5.48% and the average ROE-A-yield spread was 4.09. Unfortunately, the fact that allowed ROEs have not decreased proportionately to changing capital market conditions and the associated reduction in the costs of capital to utilities has resulted in awarded ROEs that have been well in excess of their cost of equity, with the costs being borne by consumers.

[13] The working papers for Figures 10 and 11 are appended as Exhibit I to my evidence.

FIGURE 10

ALLOWED ROES, GOVERNMENT YIELDS AND A-RATED UTILITY YIELDS (January 2004-January 2020)

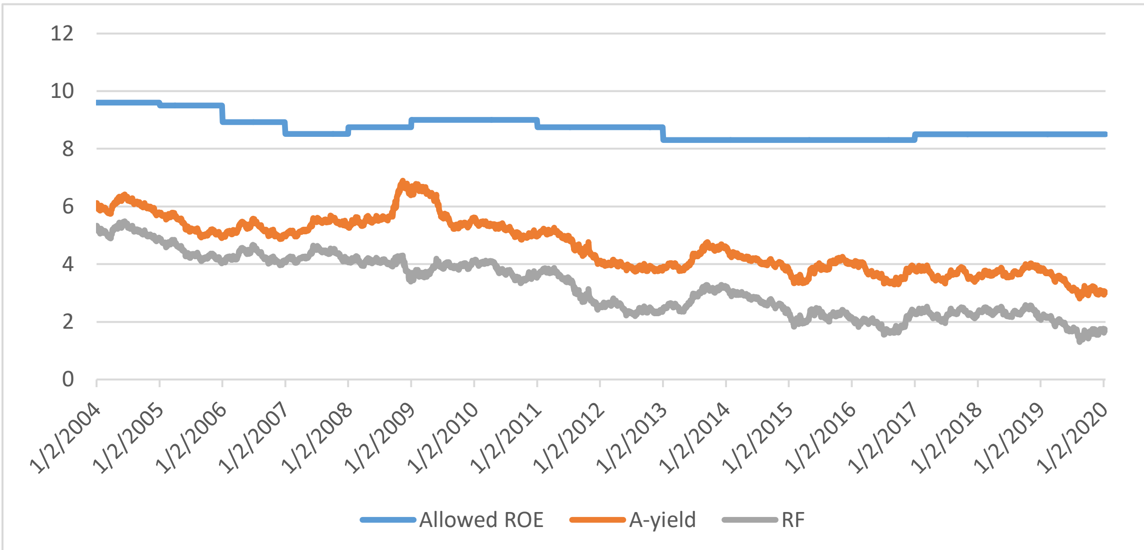
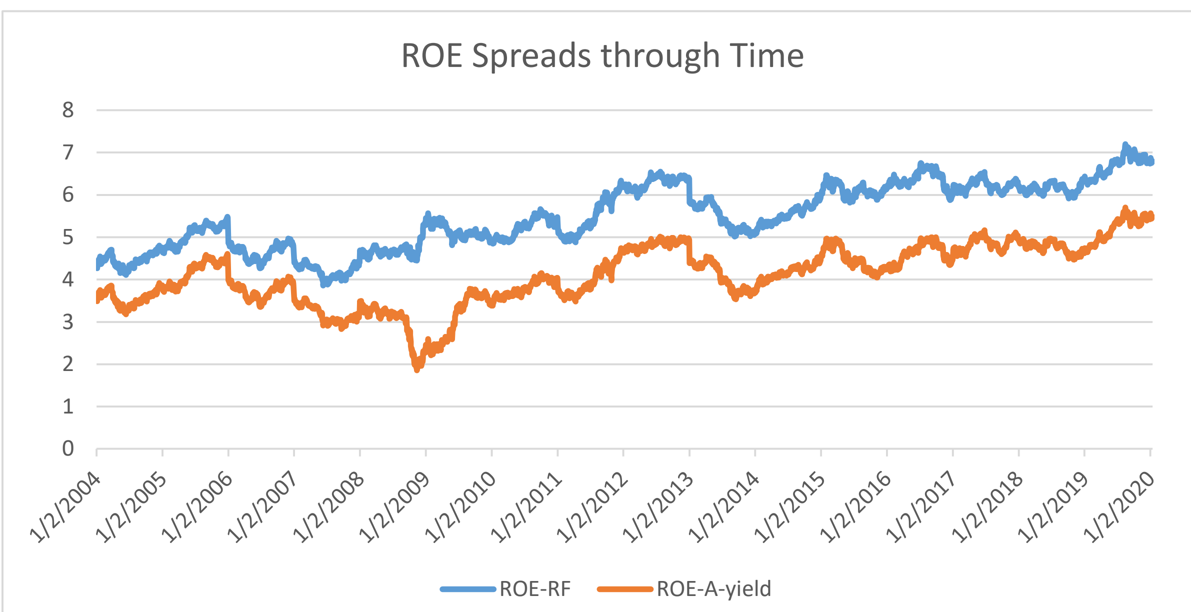


FIGURE 11

ALLOWED ROE-RF and ROE-A-YIELD SPREADS (January 2004-January 2020)



The downward "stickiness" in awarded ROEs noted above is not unique to Alberta but can be observed in other jurisdictions. A recent 2017 study examines "a dozen years' of gas and electric rate-setting decisions" in the U.S. and Canada over the 2005-2016 period.[14] This study provides evidence "demonstrating empirically that allowed returns on equity diverge significantly and systematically from the predictions of accepted asset pricing methodologies in finance." A large part of this can be explained by the fact that allowed ROEs "tend to exhibit considerable stickiness around focal 'odometer' points." Consistent with the evidence for Alberta discussed above, the authors note that "awarded ROE spreads over risk free treasuries have progressively *widened* significantly since 2005, even though systematic risk in the utilities industry has *fallen continuously* during the same time period." As a result, the authors find that:

> Indeed, if the awarded ROEs were an asset class, they would generate a mean positive abnormal return ("alpha") of *between 7.5 and 8.5 percent*, an amount that overshadows even the performance of Fortune Magazine's top twenty stock investments for the last decade.

3.2 Capital Asset Pricing Model Estimates

3.2.1 CAPM Overview

This section employs the commonly used CAPM to estimate the allowed ROE for the average regulated Alberta utility. Essentially CAPM can be used to estimate the required ROE (Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

Ke = RF + (ERm – RF) Beta

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

---

[14] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://www.semanticscholar.org/paper/The-Utility-of-Finance-Azgad-Tromer-Talley/c5913d92dc6600974956b13c9383bee6f61b731b). Appended to this evidence as Exhibit AH.

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of Financial analysts;[15]
- by over 70 percent of U.S. CFOs;[16]
- by close to 40 percent of Canadian CFOs.[17]

Of course, the CFOs and analysts are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous decisions, which is appropriate in my opinion.

A recent study by Berk and van Binsbergen (2017)[18] also provides support for the use of CAPM as the most widely used model by investors, stating:

> We find that investors adjust for risk by using the beta of the capital asset pricing model (CAPM). Extensions to the CAPM perform poorly, implying that investors do not use these models to compute discount rates.[19]

The authors go on further to highlight the fact that this model should be used by practitioners, despite its limitations, quite simply because it is the most widely used model by investors, who in turn drive equity returns:

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[15] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AI.

[16] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AJ.

[17] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AK.

[18] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AL.

[19] *Ibid.*, page 25.

> We have demonstrated that among a range of proposed models, the CAPM—though perhaps far from being a perfect model of risk—is most consistent with investor behavior. Thus, if the criterion for deciding how to compute the discount rate is to use the method investors use, **practitioners should use the CAPM**.[20]

3.2.2 Estimating RF

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate risk-free rate ("**RF**"), since it is virtually guaranteed and does not fluctuate. However, it is common practice to use the CAPM to estimate the required return on common equity over many periods, such as when trying to estimate the cost of a firm's common equity financing component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are more representative of the rate that could be obtained over longer investment horizons. This practice is consistent with previous decisions.

Similar to the approach I used in the 2016 and 2018 GCOC Proceedings, which worked well as discussed previously, I estimate RF using the approach used by the Commission in 2013, as described in paragraph 93 of the 2013 GCOC Decision. In particular, the December 2019 Consensus forecasts for government 10-year yields are [redacted] for March 2020 and [redacted] for December 2020. Considering the existing spread between 10-year and long-term bond yield spreads of 0.06%, the 2018-19 average spread between the two rates of 14 bp, and the long-term average spread of 43 bp, an estimate of 1.9% for long-term rate forecasts seems reasonable. So 1.9% will provide the upper limit of my RF estimate range. I will round up the actual prevailing long-term government yield of 1.67% as of December 19, 2019 to 1.7%, and use it as my lower bound. This gives me a range of 1.7-1.9% for my 2020-22 RF estimate, with a mid-point of **1.8%**.

3.2.3 Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium ("**MRP**"), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 7 below provides useful guidance in determining a reasonable

[20] *Ibid.*, page 32.

estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into two categories: (1) historical returns; and, (2) current (i.e., 2019) long-term market forecasts from 5 different sources. It is noteworthy that two of the sources of long-term forecasts (i.e., Horizon and Evestment) provide summary statistics based on extensive surveys of finance professionals. In particular, Horizon's report is based on the forecasts of 34 investment advisors, which includes prominent advisory firms (e.g., Aon Hewitt, Mercer, and Willis Towers Watson), several large commercial and investment banks (e.g., Bank of New York Melon, Goldman Sachs, J.P. Morgan, Merrill Lynch, Morgan Stanley and UBS), and large asset managers (e.g., BlackRock). As such, it provides a comprehensive representation of the views of finance professionals managing trillions of dollars of wealth. Similarly, the Evestment report is based upon "over 1,000 data points from over 40 consultant- and/or institutional investor-authored documents" over the period Q4, 2017 to Q1, 2019.

The Commission has previously noted that such forecasts are informative and reaffirmed this position in the **2018 GCOC Decision**, stating:

> Consistent with its determinations in previous GCOC decisions, the Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.[21]

Hence, the Commission believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity are far more relevant than market expectations determined using unrealistic assumptions, such as those provided by the utilities' experts in previous proceedings. In other words, market participant beliefs represent an important and practical "benchmark," against which any utility ROE estimate must be compared. Table 7 provides Canadian, U.S. and global historical evidence and forecasts; however, since I estimate CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence.

[21] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 97, para. 460.

TABLE 7

HISTORICAL AND FORECAST EQUITY RETURNS

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
HISTORICAL RETURNS				
1. Table 6 (Cleary evidence)	Historical: 1938-2019	Real: 6.3% GA 7.5% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[22]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl. U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017. Source: https://www.calpers.ca.gov/docs/board-agendas/201701/day1/3.3-2018-alm_presentation-2-mckinsey.pdf [23]	Historical: 1915-2014		Real: 6.5%	
Average (Range)		**Real: 6.60% (5.6%-7.5%)**	**Real: 7.07% (6.4%-8.3%)**	**Real: 5.15% (4.3%-6.0%)**
FORECAST RETURNS				
4. Institut québécois de planification financière (IQPF) and Financial Planning Standards Council (FPSC), "Project Assumption Guidelines," April 2019. Source: http://fpcanada.ca/docs/default-source/standards/2019-projection-assumption-guidelines.pdf. [24]	Long-term forecast	Nominal: 6.1%		Nominal: 6.4% (Foreign developed market equities)
5. Horizon Actuarial Services, LLC, 2019 "Survey of Capital Market Assumptions," 2019. Source: https://www.horizonactuarial.com/blog/2019-survey-of-capital-market-assumptions.[25]	Intermediate (< 10 years) Long-term (10-years or more)		U.S. Large Cap 6.03% (2.6-7.5%) 7.05% (5.3-8.8%)	Non-US Dev. Mkts. 6.83% (4.2-8.8%) 7.70% (6.6-9.3%)
6. Evestment Capital Market Assumptions, May 2019. Source: https://www.evestment.com/project/capital-market-assumptions/.[26]	Intermediate (10 years or less)		U.S. Large Cap 6.4% (5.8-7.0%)	International Markets 7.5% (6.7-8.8%)
7. Franklin and Templeton Investments,	7-year	Real:	Real:	Real -

[22] Appended to this evidence as Exhibit AM.
[23] Appended to this evidence at Exhibit AN.
[24] Appended to this evidence as Exhibit AO.
[25] Appended to this evidence as Exhibit AP.
[26] Appended to this evidence as Exhibit AQ.

"2019 Long-Term Capital Market Expectations," December 2018. Source: https://www.franklintempleton.ca/download/en-ca/common/jpfa9yjh. [27]	forecast	5.7%	5.7%	International Equities: 6.0%
8. "Capital Market Assumptions: Canadian Dollar, November 2019," BlackRock, September 2019. https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions. [28]	10-year forecast 20-year forecast	Large Cap - Nominal: 4.5% 5.1%	Large Cap – Nominal: 6.3% 6.9%	World excl. Can – Nominal: 6.6% 7.1%
Average (Range)		**Nominal 5.85% (4.5%-7.7%)**	**Nominal 6.73% (2.6%-8.8%)**	**Nominal 7.16% (4.2%-8.8%)**

The first three sources in Table 7 provide historical long-term real returns for Canadian, U.S. and global stock returns over three extremely long time periods (i.e., 82 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.6%, with a range of estimates of 5.6% to 7.5%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.6%, ranging from 7.6% to 9.5%, based solely on historical results.

The next 5 sources represent 2019 estimated long-term market returns from a number of important and reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms, investment and commercial banks, and other investment management firms). Since most of the estimates are provided in nominal terms, I adjust those made in real terms to corresponding nominal terms by adding 2% expected inflation. The Canadian market nominal estimates range from 4.5% to 7.7%, and average 5.85%. Deducting the 2% expected inflation, this translates to an average *real* return of 3.85%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.5% range over the next 5-20 years.

I believe that both historical returns and current expectations of market professionals represent the best sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table

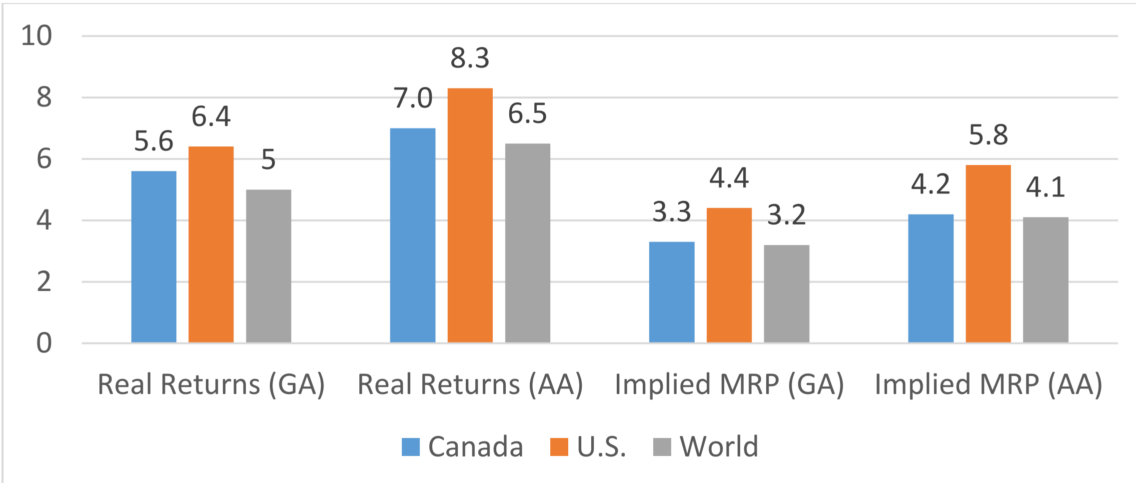
[27] Appended to this evidence at Exhibit AR.
[28] Appended to this evidence as Exhibit AS.

7 and discussed above, suggests a range of estimates in the 4.5% to 9.5% range. I advocate that an appropriate range for expected long-term Canadian stock market returns is 5-9%, and that the mid-point of 7% represents an appropriate point estimate. This is slightly below the estimate of 7.5% I advocated in 2018, but is consistent with the opinion of finance professionals. It is also consistent with the 6.95% expected market return estimate that is implied by my choice of an MRP of 5% (discussed below), my RF estimate of 1.8%, and my yield spread adjustment of 0.15%, as discussed in Section 3.2.5.

Figure 12 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. figures (5.8% and 4.4%) and slightly below the Canadian figures (4.2% and 3.3%) over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for stock and bond returns over the 1938 to 2019 period, which were 4.6% (3.7%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 13.

FIGURE 12

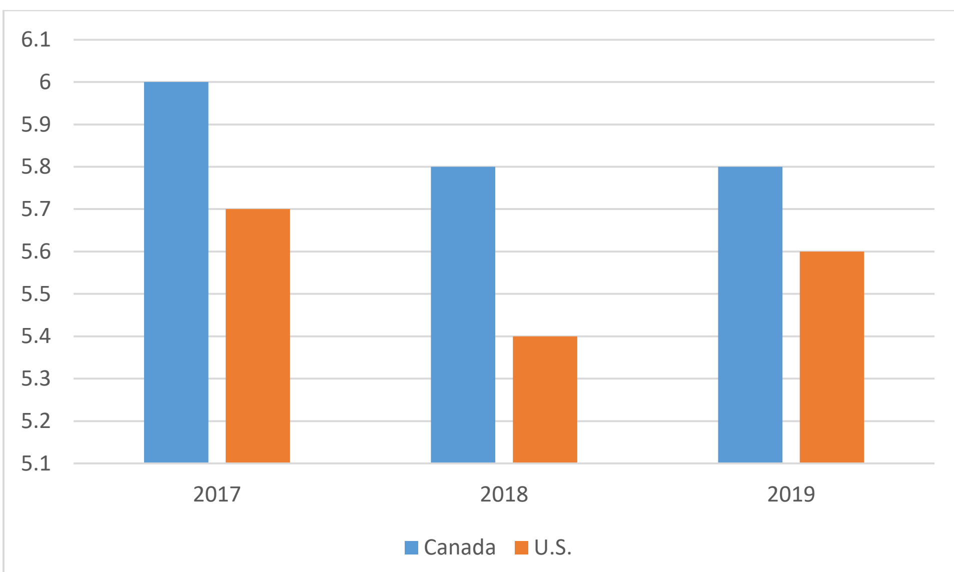
CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)



Source: Dimson, E., Marsh, P. and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[29]

FIGURE 13

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2017-2019)



Source: "Market Risk Premium and Risk Free Rate used for 69 countries in 2019: a survey," 2019, by Pablo Fernandez, Mar Martinez, and Isabel Acin, Working Paper, IESE Business School.[30]

[29] Appended as Exhibit AM, noted previously.
[30] Appended as Exhibit AT.

Based on the previous discussion of capital markets, I concluded that stock markets reflect fairly normal conditions, but are experiencing below average volatility, similar to my conclusion at the time of the 2018 GCOC Proceeding. In particular, capital market volatility both now and at the time of the 2018 GCOC Proceeding is lower than at the time of the oral hearings in both the 2016 GCOC Proceeding and the 2013 GCOC Proceeding. Therefore, I use an **MRP of 5%**, which is the mid-point of the commonly used 4-6% range. This figure is 1.7% above the long-term geometric mean MRP of 3.3%, and is the mid-point between the long-term average Canadian MRP of 4.2% and the 5.8% MRP documented by Fernandez et. al (2019). This seems appropriate in today's environment, where economic and market conditions are fairly normal in terms of valuation metrics like P/E ratios and dividend yield measures, but market volatility is below average. This is consistent with the practice of using 6% when market uncertainty is above average, using 5% when markets are normal, and using 4% during periods of extreme market and economic optimism. These estimates are also consistent with previous decisions by the AUC. For example, the AUC used an MRP range of 5-7% in the 2013 GCOC Decision[31] and 5.0-7.25% in Decision 2011-474 (the "**2011 GCOC Decision**").[32]

I know from having read numerous investment reports and from having seen numerous presentations from finance professionals that it is common practice to use a range of 3-7% for the MRP when using the CAPM to estimate required returns of equity for firms, with the large majority of MRP estimates falling in the 4-6% range. In fact, it is so common, that it is almost assumed. Similarly, it has also always been the case that the MRP would be adjusted upwards during higher periods of uncertainty, and downwards during periods of less uncertainty. I provide some strong evidence below regarding MRPs which is included in two research articles written by prominent finance professors.

In a 2013 working paper, Aswath Damodaran discusses MRP estimation (which he refers to as the equity risk premium (ERP)).[33] In this paper, Dr. Damodaran discusses the results of

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[31] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 115.
[32] Decision 2011-474, 2011 Generic Cost of Capital, para. 59.
[33] Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition," Aswath Damodaran, Stern School of Business, New York University. This article is appended as Exhibit AU to this evidence.

Merrill Lynch from its monthly surveys of global institutional investors:

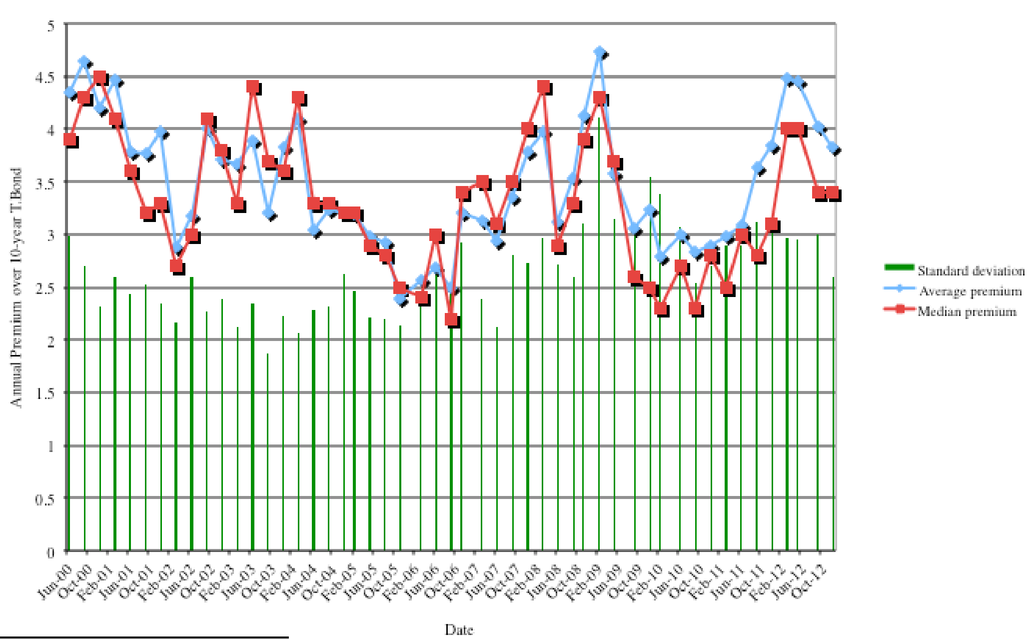
> Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update.[34]

This evidence verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, the 3-4.5% range), and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran then proceeds to discuss the results of Graham and Harvey (2013)'s surveys of CFOs regarding MRPs:

> To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.

Figure 2: CFO Survey Premiums



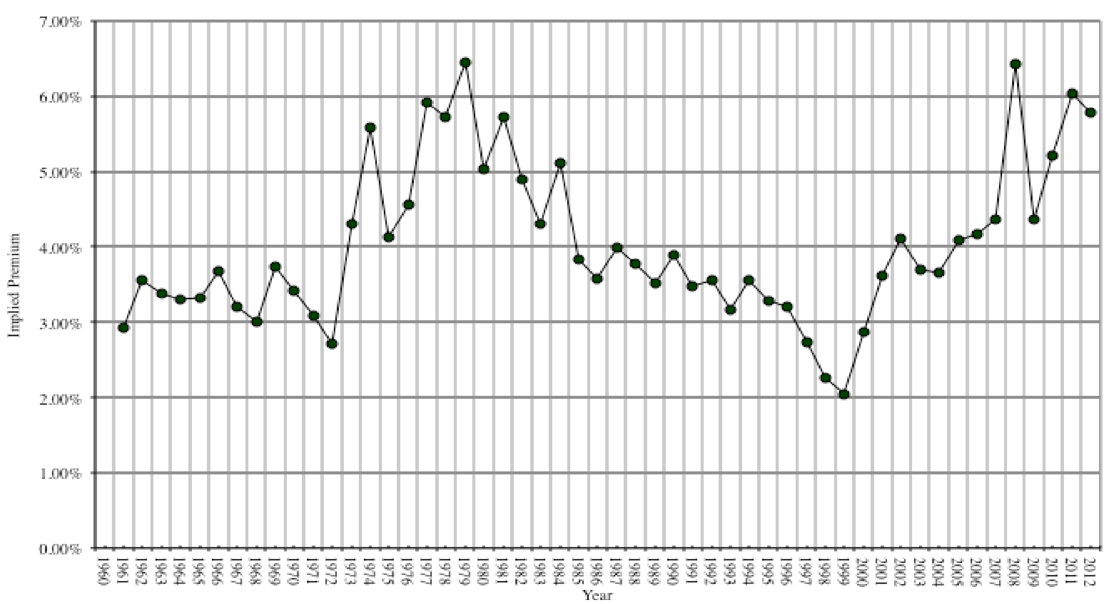
[34] *Ibid.*, pages 18-19.

> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[35]

This evidence also verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, in the 2.47-4.74% range) over the 2000-2012 period, and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran also discusses the implied MRPs in the S&P 500 Index from 1960-2012 and produces Figure 9, below:[36]

Figure 9: Implied Premium for US Equity Market



This evidence also shows that implied MRPs generally lie within the 3-6% range (and in fact are never less than 2% or above 6.5%), and that the MRP increases during periods of uncertainty (e.g., 1979 and 2008), and declines during periods of less uncertainty (e.g., the boom in stock markets at the end of the 1990s).

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[35] *Ibid.*, pages 20-21.
[36] *Ibid.*, page 74.

Dr. Damodaran discusses his own approach to estimating and using MRPs when valuing companies, stating:

> On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5% equity risk premium for mature markets in 2010. With the increase in implied premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2013, I will be using a slightly lower equity risk premium (5.80%), reflecting the drop from 2012.[37]

This evidence verifies that a well-respected finance professional, textbook author, and provider of financial data uses MRPs in the 4-6% range and varies his choice of MRP so that it increases during periods of uncertainty, and declines during periods of less uncertainty.

The results of a 2013 survey by Graham and Harvey was discussed above by Dr. Damodaran.[38] I would also note the following conclusions Dr. Graham and Dr. Harvey reached based on their ongoing surveys of CFOs:

> the CFOs believe that the “risk premium” is a longer-term measure of expected excess returns and best covered by our question on the expected excess return over the next ten years – rather than the one-year question. Three-fourths of the interviewees use a form of the Capital Asset Pricing Model (which is consistent with the evidence in Graham and Harvey, 2001).

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[37] *Ibid.*, page 79.

[38] “The Equity Risk Premium in 2013,” John Graham and Campbell Harvey, Fuqua School of Business, Duke University. “The Equity Risk Premium in 2013,” John Graham and Campbell Harvey, Fuqua School of Business, Duke University. This survey is appended to this evidence as Exhibit AV.

> They use a measure of the risk premium in their implementation of the CAPM.[39]

These conclusions are consistent with the long-term (with adjustments) approach to estimating the MRP that I advocate. It also shows that 3/4ths of CFOs use some version of the CAPM.

Further, Dr. Graham and Dr. Harvey examine the relationship between MRPs and two other common measures of risk aversion that I have referenced previously – the VIX and yield spreads:

> Finally, we consider two measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.52. If the closing day of the survey is used, the correlation is roughly the same. Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.

> We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.54.[40]

This evidence confirms that MRPs tend to increase as risk aversion increases, and decrease as risk aversion declines, which is consistent with my approach to estimating MRPs.

3.2.4 Estimating Beta

We now require a beta estimate to apply the CAPM. Appendix B of my 2018 evidence examines the historical evidence provided by three of the utilities' experts in 2018 that confirms the following three important facts:

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[39] *Ibid.*, page 8.
[40] *Ibid.*, pages 14-15.

1. Canadian utility beta estimates over the previous 22-25 years averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate.
2. Canadian utility beta estimates have never come close to one, with maximum values in the 0.6-0.8 range. Neither have U.S. utility beta estimates ever come close to one for that matter. Hence the use of traditional adjusted betas is totally inappropriate.
3. U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered.[41] This is consistent with the higher level of business risk associated with U.S. utilities.

Based on these observations, I recommend the following approach for determining reasonable beta estimates, which can be used by the Commission when they receive a wide spread in beta estimates:

1. Ensure beta estimates are from reasonable comparators – i.e., exclude U.S. utility beta estimates.
2. If there is a desire or need for "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35, or even 0.45, rather than toward 1.0, as is done with published betas provided by services such as Bloomberg and Value Line.
3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

As noted above, a review of the 2018 utilities' experts' evidence showed that Canadian utility beta estimates over the last 22-25 years have averaged somewhere between 0.20 and

[41] For example, Appendix B showed that Mr. Hevert's historical average Canadian beta estimates of 0.34 (monthly) and 0.38 (weekly) are just over half their U.S. counterpart estimates of 0.61 (monthly) and 0.72 (weekly), after accounting for leverage differences. The implied "unlevered" U.S. betas (0.234 monthly; 0.278 weekly) are almost double those for the Canadian utilities (0.131 monthly; 0.140 weekly).

0.40 – with 0.35 representing the best estimate. In the 2018 GCOC Decision, the Commission calculated a historical utility beta average of 0.47, based on data that excludes the 1998-2007 period, in order to discard the abnormally low estimates obtained over the 1998-2002 period. It is important to recognize that as an average, this implies approximately half of the estimates would be both below and above this estimate of central tendency. The fact that this average is so close to the 0.45 that I have used in previous Proceedings confirms the appropriateness of the range that I used and the judgment I employed in determining my beta estimate, which was consistent in the 2013, 2016 and 2018 GCOC Proceedings, and which lies at the mid-point of the range of reasonable beta estimates that I recommended to the Commission in 2018.

Table 8 provides beta estimates for several Canadian utilities as of January 2020. The average is 0.42, which decreases slightly to 0.39 if we eliminate TransAlta and Northland, which are primarily non-regulated utilities. If we also exclude Canadian Utilities Ltd. and ATCO, which are holding companies that include interests in non-regulated assets, and we also exclude Algonquin, which also has a mix of regulated and non-regulated assets, then the average increases to 0.50, primarily due to the heavier weight placed on the Enbridge beta estimate of 0.975. Taking the average of these three beta estimates arising from Table 8, we get 0.436. Table 8 also provides the January 2020 TSX Utility Sub-Index estimate from Bloomberg of 0.381. Taking the average of this estimate and 0.436, we end up with a 0.41 estimate.

TABLE 8

BETA ESTIMATES – JANUARY 2020

Firm	Beta
Fortis	0.254
Emera	0.285
TransAlta	NA
Northland Power	0.605
Algonquin Power	0.305
ATCO	0.288
Cdn Utilities Ltd.	0.215
Enbridge	0.975
Average	0.418
Average excl. TransAlta and Northland	0.387
Average (Fortis, Emera, Enbridge)	0.504
TSX Utility Sub-Index	0.381

Source: Bloomberg, January 2020.

Based on the evidence provided in Table 8 and combining it with long-term historical averages, a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. The current average of estimates I note above is 0.41. In order to be consistent with my recommendations in the 2013, 2016 and 2018 GCOC Proceedings, I will use the mid-point figure of my recommended range (i.e., 0.30-0.60) of **0.45** as my best point estimate, which is above the long-term average of around 0.35.

3.2.5 Final CAPM Estimates

Government bond yields are extremely low, both in absolute terms and by historical standards. A-rated Canadian utility bond yield spreads were sitting at 130 bp in December of 2019, similar to the 126 bp spread observed in November 2017, much lower than the 200 bp observed in February of 2016, but still slightly above the long-term average spread of 100 bp. While this spread is quite small, I will adjust for it as I have in previous proceedings. Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian Utilities.[42] Consistent with this research, I will add half of the

[42] Refer to: A. Garcia and J. Yang, "Understanding Corporate Bond Spreads Using Credit Default Swaps," Bank of Canada Review, Autumn 2009. This article is appended as Exhibit AW to this evidence.

"above average" yield spread, or 0.15%, to my CAPM estimate to account for this time varying risk premium.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous Commission decisions, and consistent with long-term estimates. Combining these items we get a range of CAPM estimates for the required equity return for the average regulated Alberta utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests an ROE of 4.7%.

TABLE 9

CAPM ESTIMATES – 2020-2021

Estimate	RF (%)	MRP (%)	Beta	Spread Adjust. (%)	Financial Flex. (%)	Ke (%)
Max	1.9	5.5	0.60	0.15	0.50	5.85%
Min	1.7	4.5	0.30	0.00	0.50	3.55%
Best Estimate	1.8	5.0	0.45	0.15	0.50	4.7%
Adjusted Best Estimate						**5.0%**

The CAPM parameters used (i.e., RF of 1.8%, MRP of 5% and the spread adjustment of 0.15%) imply a required return on the entire market of 6.95%, which is in line with the long-term market return expectations of finance professionals provided in Table 7, and is also in line with the long-term real returns on Canadian stocks. It is also consistent with my best estimate of 7.0% for the long-term expected return on the market that I discussed previously. The 4.7% estimate for the utilities is 80 bp below my CAPM estimate in the 2018 GCOC Proceeding, all of which is due to the 80 bp decline in my RF estimate (which was 2.6% in 2018), reflecting the decline in both long-term rates and forecasts regarding future long-term yields. As noted in my BYPRP analysis in Section 3.4, it is common to add a risk premium between 2 and 5% to a company's bond yield to determine its cost of equity. As such, we could consider a company's bond yield plus 2% as a minimum cost of equity for a firm. Given that A-rated utilities' bonds were yielding 3% in December of 2019, this implies a minimum cost of equity of 5%, 30 bp above my CAPM estimate above, so I apply judgment and use **5%** as my CAPM estimate.

3.3 Discounted Cash Flow Estimates

3.3.1 DCF Model Overview

The Commission has appropriately taken DCF estimates into account in making previous decisions as to the appropriate ROE. I use two approaches and apply the DCF model as at the end of 2019 to:

1. find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the "average" company in the market; and,
2. apply the models at the industry level using numbers that are representative of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The Dividend Discount Model ("**DDM**") is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely. The constant-growth model can be represented as:

$$\text{Price} = D_0(1 + g) / (Ke - g) = D_1/(Ke - g)$$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/\text{Price})\times(1 + g) + g$$

3.3.2 Market DCF Estimates

Table 1 showed that real GDP growth has averaged 2.5% over the 1992 to 2018 period, which provides one potential estimate of long-term growth that could be used in the single-stage model, since one might expect long-term growth for the overall market to gravitate towards this figure. Similar assumptions are commonly made by financial analysts. The December 2019 Consensus forecasts suggested real GDP growth for Canada of [redacted] during 2019 and 2020, while the Bank of Canada October 2019 MPR suggested growth of 1.5% for 2019, 1.7% for 2020 and 1.8% for 2021. The October 2017 Consensus Forecasts obtained long-term estimates from forecasters, with the forecasts averaging 1.7% real GDP growth for Canada over the 2023-2027 period, while the Conference Board of Canada's 2019 Provincial Outlook Long-Term Economic Forecast estimated 1.7% real growth for Canada over the 2023-2027 period, with 1.8% growth estimated for 2022. The mid-point of these longer term estimates of real growth is 1.75%, which provides another reasonable estimate of future Canadian economic growth. Of course, we are trying to estimate a "nominal" required rate of returns, so we should use nominal GDP growth as "g." We can estimate nominal growth rates by applying the 2% Bank of Canada inflation target, [redacted] Doing so, we get the following long-term nominal Canadian GDP growth rate estimates that correspond to the two real growth rates noted above: 4.5% and 3.75% - where 4.13% represents the mid-point of these figures. These growth rates are in line with those used by security analysts when they use single-stage growth models to value securities (i.e., they usually use numbers in the 3-5% range *when* they use single period models).

The dividend yield for the S&P/TSX Composite Index as of January 2020 was 3.0%. This is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent 12-month period. Substituting the average nominal GDP growth estimate of 4.13% noted above into the single-stage DDM equation provided above, we get the following estimate for the implied equity return for the market as a whole for 2020:

$$Ke = (0.030)\times(1.0413) + .0413 = 0.0725 \text{ or } \mathbf{7.25\%}$$

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, this estimate seems to be reasonable. It is above, but not out of line with, my long-term forecast for expected market returns and my CAPM market estimate, both of which are 7.0%, and it is consistent with the market forecasts of expected future returns that were provided in Table 7, as discussed earlier.

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

I consider the long-term GDP growth forecasts that translated into a 3.75% nominal GDP growth rate as my short-term growth rate (g_S), and use the historical long-term GDP nominal growth rate average of 4.5% as the long-term growth rate (g_L). Assuming it takes four years to get back to this long-term expected growth rate, then we would use H = 2, which provides an estimate for Ke of 7.57%. If we assume that this return to long-term growth takes longer (say 8 years), then H = 4, and we get an estimate for Ke of 7.52%. The mid-point of these two estimates is 7.55%.

Combining the results from the two DDM models, we get estimates for Ke for the market in the 7.25-7.57% range. Taking the mid-point of the single-stage DDM estimate of 7.25% and the 7.55% estimate from the H-model, we arrive at 7.4% as my best estimate of the implied return on the market using DCF models. This number is reasonable, albeit above my estimate for future market returns and my CAPM market estimate of 7.0%, discussed previously. DCF models will work better in aggregate than for Canadian utilities, which leaves us with the issue of how to adjust these figures into a reasonable implied return for utilities that possess considerably less risk than the average company in the market. At minimum, we could say that the market DCF estimates suggest that utility returns should be *lower than 7.4%*.

3.3.3 Alberta Utility DCF Estimates

I will now apply both of the DCF models discussed above to Canadian utilities. Of course, determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's **sustainable growth rate,** which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the ROE, as shown below:

$$g = (1 - \text{payout ratio}) \times \text{ROE}.$$

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures that are generally close to allowed ROEs, which do not usually fluctuate by large amounts.

Table 10 below includes summary statistics on dividend yield, payout ratios and ROE for the 8 Canadian utility firms that were included in Table 8. This data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using our two DCF models. Panel A reports the average, median, maximum and minimum figures for all 8 utilities for the December 2019 dividend yield ("**DY**"), the average 5-year DY, the 2018 payout ratios and ROEs, and the 2007-18 averages for payout and ROE.[43] Panel B reports the same statistics after eliminating TransAlta and Northland, and Panel C

[43] Payout ratios were "capped" at 100% to control the influence of extreme payouts on "averages" - this process obviously had no effect on the reported medians.

after also eliminating ATCO, Canadian Utilities, and Algonquin. The working papers for Table 10 (and Table 11) are appended to my evidence as Exhibit J.

TABLE 10

DCF INPUT ESTIMATES – 2007-2019 FIGURES

	DY (Dec 19)	5-year Avg DY	2018 Payout	Avg Payout (07-18)	2018 ROE	Avg ROE (07-18)
Panel A						
Average	4.03	4.19	90.93	73.08	8.36	8.68
Median	4.07	4.41	100.00	70.98	7.09	9.10
Max	5.67	5.18	100.00	100.00	35.64	12.93
Min	3.15	2.87	73.15	57.54	-11.17	4.67
Panel B						
Average (excl TransAlta and Northland)	4.13	3.94	92.39	67.01	7.07	10.31
Median	4.07	4.10	100.00	68.07	7.09	11.06
Max	5.67	4.55	100.00	92.38	11.71	15.09
Min	3.24	2.87	74.24	43.38	3.13	6.70
Panel C						
Average (Fortis, Emera, Enbridge)	4.45	4.18	91.41	75.66	5.13	10.06
Median	4.31	4.40	100.00	78.22	4.49	10.79
Max	5.67	4.55	100.00	91.40	7.78	14.25
Min	3.38	3.59	74.24	57.17	3.13	5.13

Data Source: Morningstar at www.morningstar.ca.

The summary statistics included above appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. Payout ratios gravitating towards an average of 67-92%, are in line with historical figures and also with the high dividend paying nature of such profitable, slow growing firms. Similarly, dividend yields in the 2.9-5.7% range are in line with that of the S&P/TSX Utilities Index. The ROE averages in the 5.1-10.3% range are also reasonable.

It is difficult to find "typical" or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 11 provides estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 10. These are calculated using the formula above (i.e., g = (1 – payout) × ROE). Column 2 uses the average and median ROE and payout figures for 2018, while column 3 uses the averages over the 2007 to 2018 period. The median and average growth rates range from 0% to 3.53%, with an average (median) of 1.65% (1.42%). This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.75-4.5% range.

TABLE 11

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

	Implied g (2018)	**Implied g (07-18)**	**Implied Ke (2018 g and Dec 2019 DY)**	**Implied Ke (07-18 g and 5-year DY)**
Average	0.76	2.34	4.82	6.63
Median	0.00	2.64	4.07	7.16
Average (excl TransAlta and Northland)	0.54	3.40	4.69	7.47
Median	0.00	3.53	4.07	7.77
Average (Fortis, Emera, Enbridge)	0.44	2.45	4.91	6.73
Median	0.00	2.35	4.31	6.85
Average of 6 averages g = 1.65%				**Average of 6 averages Ke = 5.88%**
Average of 6 medians g = 1.42%				**Average of 6 medians Ke = 5.71%**

The final two columns in Table 11 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 10). Recall this formula can be represented as follows when we begin with the dividend yield based on dividends over the previous 12 months: $Ke = (D_0/Price)\times(1 + g) + g$. The working papers for Table 11 are included in Exhibit K.

These estimates range from a low of 4.07% using 2018 implied growth and December 2019 DY median numbers, to a high of 7.77% using 2007-18 median values after excluding Transalta and Northland. As mentioned, it is difficult to determine which group provides the most representative statistics, so it is useful to determine the average of all these estimates. The average of all 6 Ke estimates determined using averages is 5.88%, while the average of the 6 numbers calculated using the medians is 5.71%. I will assign a best estimate single-stage DDM estimate at the mid-point of 5.8%, almost identical to my 2018 single-stage DCF estimate of 5.9%. This estimate is below my 7.25% single-stage growth DDM estimate for the market, which is reasonable since regulated utilities are considerably less risky than the average company. If we add 50 basis points for flotation costs, we end up with a range of 4.6%-8.3%, with a best estimate of 6.3%.

While I believe these estimates are reasonable, as are the growth rates upon which they are based, the Commission expressed concerns in 2018 regarding the use of low growth rates, that could be negative real growth rates based on inflationary expectations. I disagree with this assertion regarding the reasonableness of these growth estimates. For example, as noted in an information response during the 2018 Proceeding (UCA-AUC-2018JAN26-012):

> Dr. Cleary notes that the average long-term sustainable growth rate he uses in his single-stage model is 1.9% and his average short-term estimate used in the H-model is 1.0% while his long-term sustainable growth rate is 2.8%. These estimates are very reasonable. For example, they are in line with the long-term (i.e., terminal) growth rates used by analysts in some of the equity analyst reports provided by the utilities during the 2018 Proceeding. Some of the analysts' "best" estimates of terminal growth rates are reported below, which are in the **0.0%-2.0% range and average 1.38%**.
>
> Fortis Inc.: BMO =1.0%; CIBC = 2.0%.
> Canadian Utilities: BMO = 1.5%;
> AltaGas: BMO = 0.0%; CIBC = 2.0%.
> Enbridge Inc.: CIBC = 1.8%.
> Hydro One Limited: CIBC = 1.39%.

It is also important to recognize, as noted by the Commission in the 2018 GCOC Decision:

> The Commission recognizes that the utilities are, as Dr. Cleary stated in his evidence, essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.[44]

Further, even the assumption of nominal GDP growth (i.e., average growth) is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for dramatic growth, as also acknowledged previously by the Commission, in the 2013 GCOC Decision:

> However, the Commission is also mindful that, as both experts acknowledged, **the GDP growth rate may be an ambitious target** for long-run earnings growth in respect of low-risk, mature, utilities.[45]

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the implied growth rates determined using 2018 payout ratios and ROEs, which are reported in column 2 of Table 11. I then denote as g_L the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 11. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 12 below. The working papers for Table 12 are appended to my evidence as Exhibit K.

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44 Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 92, para. 438.
45 Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].

TABLE 12

H-MODEL ESTIMATES

Using all 8 Utilities		
	H=2	**H=1**
Current D0/P0	0.0403	0.0389
gs (current sustainable g)	0.0000	0.0000
gL (long-term sustainable g)	0.0264	0.0264
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0000	0.0000
g1	0.0066	0.0132
g2	0.0132	0.0264
g3	0.0198	0.0264
g4	0.0264	0.0264
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0657**	**0.0667**
Excl TransAlta and Northland		
Current D0/P0	0.0413	0.0413
gs (current sustainable g)	0.0054	0.0054
gL (long-term sustainable g)	0.0340	0.0340
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0054	0.0054
g1	0.0125	0.0197
g2	0.0197	0.0340
g3	0.0269	0.0340
g4	0.0340	0.0340
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0743**	**0.0755**
Fortis, Emera, Enbridge		
Current D0/P0	0.0445	0.0445
gs (current sustainable g)	0.0044	0.0044
gL (long-term sustainable g)	0.0245	0.0245
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0044	0.0044
g1	0.0094	0.0144
g2	0.0144	0.0245
g3	0.0195	0.0245

g4	0.0245	0.0245
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0683**	**0.0692**
AVERAGE	**0.0694**	**0.0705**

The Ke estimates lie within the range of 6.6% to 7.6%. The average estimate is 6.94% if we assume a 4-year transition in growth rates (i.e., H =2), and is slightly higher at 7.05% if we assume a 2-year transition. Combining these results with a 0.50% allowance for flotation costs, we get the following ranges and point estimates: 7.1-8.1% with a best estimate of 7.5%. The Ke estimates from the H-Model are higher than the averages derived using the single-stage model. This is because the model implicitly assumes that growth rates will gravitate to longer term average rates, which were higher than the implied rates using 2018 data only. I weight the estimates from the constant-growth model and the H-Model equally in arriving at my final DCF estimates.[46]

A summary of the DCF estimates determined above is provided in Table 13 for the market and for Alberta utilities. The DCF analysis suggests a 7.4% required return on the market with a range of 7.25-7.57%. As discussed previously, this estimate is 0.40% above my CAPM market estimate of 7% and is consistent with, but at the high end of current estimates of finance experts and historical long-term real stock returns. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return with a range of 4.6-8.3% and a best estimate of 6.9%, which is identical to my 2018 estimate. This estimate is 1.0% below my DCF estimate for the market (if we also adjusted the market estimates 50 bp for flotation costs), which is consistent with the below-average risk of utilities.

[46] Having stated above my basis for disagreement with the Commission's concern regarding the use of low growth rates, in order to address this concern for the Commission, in Appendix B, I recalculate both of my DCF estimates using alternative growth rates. My revised single stage DCF estimates are determined using only the 2006-2018 sustainable growth rates from Table 11 (which are higher than the 2018 implied sustainable growth rates). The resulting single-stage DCF estimate is 7.05%, or 7.55% after flotation costs. I also recalculate my H-model DCF estimates using the expected GDP nominal growth rate (an ambitious target for mature regulated utilities) as my short-term growth rate and use the 2006-2018 sustainable growth rates from Table 11 as the long-term growth rates. The resulting cost of equity estimate is 7.15%, or 7.65% after flotation costs. I would stress that I do not agree with this approach; however, I do so in order to provide direction for the Commission.

TABLE 13

DCF ESTIMATE SUMMARY

Year	Model	Minimum	Maximum	Best Estimate	Flotation Costs Adj.	Range	Final Estimate
Panel A: Market Estimates							
Single-Stage				7.25	0.50		7.75
H-Model		7.52	7.57	7.55	0.50		8.05
Combined		7.25	7.57	**7.4**	0.50		**7.9**
Panel B: Utility Estimates							
Single-Stage		4.1	7.8	5.8	0.50	4.6-8.3	6.3
H-Model		6.6	7.6	7.0	0.50	7.1-8.1	7.5
Combined		4.1	7.8	**6.4**	0.50	4.6-8.3	**6.9**

3.4 Bond Yield Plus Risk Premium Estimates

The BYPRP approach adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[47] and by over 50 percent of Canadian CFOs.[48]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable *market-determined* bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

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[47] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute.
[48] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" Multinational Finance Journal 15-3, 2011.

This approach provides useful reasonableness checks on CAPM and other estimates, and employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s. In fact, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta.

The first step is to obtain an estimate of the cost of long-term yields on a typical utility. As of January 13, 2020 the yield on long-term A-rated Canadian utility bonds was 3.02% according to the Bloomberg data used to construct Figure 3. This number is close to the yields on outstanding Canadian utility bonds around the same time. For example the following yields were observed as of December 19, 2019:

Description	S&P	DBRS	Moody's	Maturity Date	Seniority	Yield
Fortis Alberta Inc		A(low)	Baa1	09/2048	SNR Unsec	3.01
Fortis BC Inc		A(low)	Baa1	12/2049	SNR Unsec	3.05
CU Inc	A-	A		11/2048	SNR Unsec	3.02
Enbridge Gas Inc	A-	A		08/2049	SNR Unsec	3.01
Hydro One Inc	A-	A(high)	A3	06/2049	SNR Unsec	3.03

This evidence implies that 3.02% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of

2.5%.[49] Combining this information, I obtain the following 2021-2022 estimates for Ke according to this approach:

Minimum: Ke = 3.0 + 2 = 5.0%

Maximum: Ke = 3.0 + 3 = 6.0%

Best Estimate: Ke = 3.0 + 2.5 = 5.5%

If we add 50 bp for flotation costs, we end up with Ke estimates in the 5.5-6.5% range, with a **best estimate of 6.0%**.[50] This is 50 bp lower than my estimate in the 2018 GCOC Proceeding, which reflects the fact that A-rated bond yields have declined from 3.5% to 3.0% when I prepared my evidence in that proceeding. This 6.0% estimate is close to the mid-point of my CAPM and DCF estimates – being 1% above my CAPM estimate of 5% and 0.90% below my DCF estimate of 6.9%.

3.5 ROEs and Price-to-Book Ratios

Figure 14 depicts annualized quarterly ROE data for Canadian firms and Canadian utilities from Q1-2003 to Q3-2019. Over this period, the average ROE for all companies was 10.4%, 10.6% for all non-financial companies, and 8.1% for utilities. We can see that it was generally a good period for all types of companies in terms of ROEs, which were between 2.9 and 15.6% for all companies, 2.0 and 16.5% for all non-financials, and 0.5 and 23.7% for utilities. The working papers for Figure 14 are appended to my evidence as Exhibit L.

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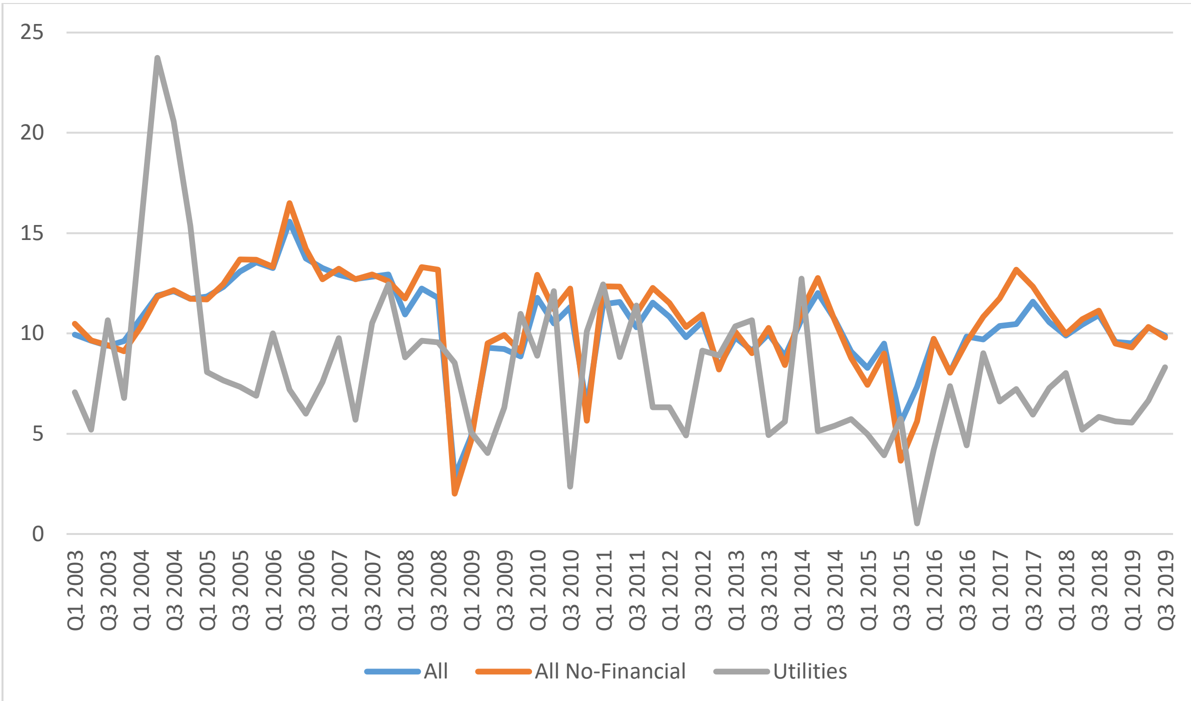
[49] For example, Exhibit AX provides an example of implementing the BYPRP approach for IBM from the CFA curriculum, where a risk premium of 2.75% is added to cost of IBM's debt. Clearly IBM is riskier than a regulated A-rated utility, so 2.5% is very reasonable by comparison.

[50] To provide perspective for the Commission, I note that the current allowed ROE of 8.5% implies a risk premium of 5.5%. The spread between the allowed ROE and the A-rated utility yield in January 2004 was 3.5%, implying Ke of 6.5% today, while the 2004-2019 average ROE-A-yield spread of 4.1% implies Ke of 7.1%.

FIGURE 14

CANADIAN ROEs– Q1-2003 to Q3-2019



Data Source: CANSIM.

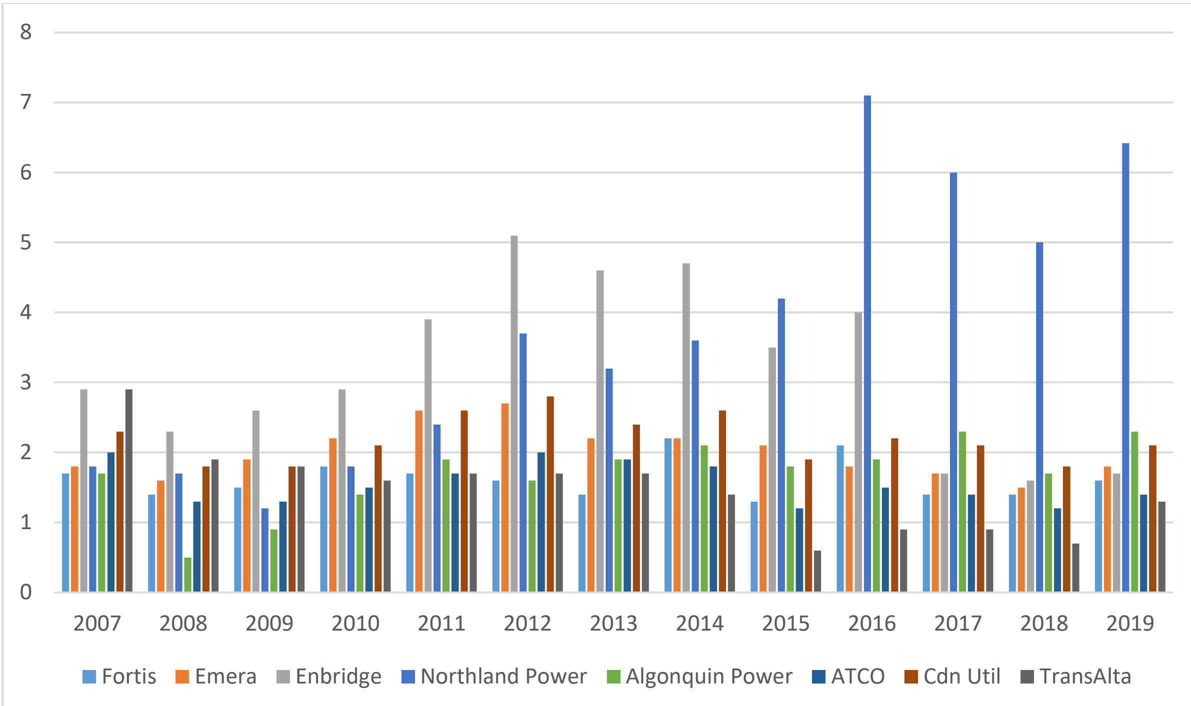
Tables 15 and 16 (in Section 4.2) provide similar positive results for Alberta utilities over the 2005 to 2018 period according to their Rule 005 reports with annual averages ranging from 8.8% to 10.2%, and always above the allowed ROE. The 14-year overall average was 9.38%, which is 0.72% above the average allowed ROE over the period of 8.67%. So overall, we can say that these utilities have generated ROEs that were consistently well above the allowed rates. The average ROE of 9.38% is higher than the 2007-Q3/2019 average of 8.1% provided above in Figure 14 for Canadian utilities, and the 2007-2018 average of 8.7% provided earlier in Table 10 for the Canadian utilities used in the DCF analysis.

ROE data suggest that Alberta utilities have earned an ROE that is only 1% lower than the average Canadian company, yet we know that they are less risky than average. In fact, the reported ROE numbers are well above the required return estimates determined using the CAPM, DCF and BYPRP approaches, with best estimates of 5.0%, 6.9% and 6.0%. All of this suggests that Alberta utilities would make attractive investments. Certainly, from an investor’s point of view, low-risk utilities that have regulated returns that exceed *required* rates of return based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 5.0% figure that was determined above. If the utility earned the currently allowed ROE of 8.5%, then that investor would surely be pleased. Of course, this does not mean that the actual return on the stock was 8.5%; however there is an obvious relationship between the two. I examine this relationship below by reference to price-to-book ("**P/B**") ratios and stock returns.

I begin by considering the P/B ratios for the utilities discussed previously in the DCF analysis. The individual P/B ratios for the firms are presented in Figure 15. It is obvious that almost all of the ratios are above 1 throughout the entire period, with the exception of the P/B ratios for TransAlta from 2015 to 2018, and for Algonquin in 2008 and 2009. The summary statistics provided in Table 14 show that the average P/B ratio has generally exceeded 2 since 2011, and is presently in the 1.7 to 2.3 range, depending on which sub-set of firms is considered. The working papers for Figure 15 and Table 14 have been appended to my evidence as Exhibit M.

FIGURE 15

UTILITY P/B RATIOS – 2007-2019



Data Source: Morningstar at www.morningstar.ca.

TABLE 14

P/B RATIO SUMMARY STATISTICS (2007-2019)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Average	2.14	1.56	1.63	1.91	2.31	2.65	2.41	2.58	2.08	2.69	2.19	1.86	2.33
Median	1.90	1.65	1.65	1.80	2.15	2.35	2.05	2.20	1.85	2.00	1.70	1.55	1.75
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	4.20	7.10	6.00	5.00	6.42
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.40	0.60	0.90	0.90	0.70	1.30
Average excl TransAlta and Northland	2.07	1.48	1.67	1.98	2.40	2.63	2.40	2.60	1.97	2.25	1.77	1.53	1.82
Median	1.90	1.50	1.65	1.95	2.25	2.35	2.05	2.20	1.85	2.00	1.70	1.55	1.75
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	2.30	1.80	2.30
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.80	1.20	1.50	1.40	1.20	1.40
Average (Fortis, Emera, Enbridge, TransCda)	2.13	1.77	2.00	2.30	2.73	3.13	2.73	3.03	2.30	2.63	1.60	1.50	1.70
Median	1.80	1.60	1.90	2.20	2.60	2.70	2.20	2.20	2.10	2.10	1.70	1.50	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	1.70	1.60	1.80
Min	1.70	1.40	1.50	1.80	1.70	1.60	1.40	2.20	1.30	1.80	1.40	1.40	1.60

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least "fair," if not above fair. This is consistent with the Commission's statement in the 2011 GCOC Decision. The Commission confirmed the usefulness of P/B ratios in the 2013 GCOC Decision, noting:

> Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity.[51]

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[51] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 221.

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[52] P/B = (ROE – g) / (Ke – g)

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke. This is consistent with the discussion above. If we "plugged" the average 2003-Q3/2019 utility index ROE of 8.1% into the equation, as well as current average P/B ratios of 2.33, 1.82, and 1.70, and then used a 3% long-term growth rate, we would get implied Ke figures of 5.18%, 5.80% and 6.00% respectively. Alternatively, if we used the current allowed ROE of 8.5% for Alberta utilities, we would get implied Ke figures of 5.36%, 6.02% and 6.23% respectively. These estimates are all in line with my overall ROE estimate of 6%, or 5.5% if we subtract the 0.50% that was added for financial flexibility. While I will not assign any weight to this estimate for purposes of determining Ke, the bottom line of this discussion is that the P/B ratios for utilities reported above indicate that Canadian utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time.

3.6 Summary of ROE Calculations

I have weighted all three estimates equally, as I did in my 2013, 2016 and 2018 evidence, because all three methods are used in practice. CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to DCF approaches, they were used by:[53]

- only 15% of U.S. CFOs - versus over 70% for CAPM;[54]
- about 12% of Canadian CFOs - versus close to 40% for CAPM.[55]
- Not widely used, while CAPM was used by the majority of investors.[56]

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[52] This is true if we use the following sustainable growth rate for "g" in the DDM: g = (1 – payout) × ROE.
[53] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."
[54] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243.
[55] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011.
[56] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32.

These advantages also make CAPM more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also gave equal weighting to the BYPRP approach which is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for both borrowing rates and risk. In fact the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned earlier. Thus the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such I believe it is intuitively sound and hence BYPRP estimates are excellent reflections of existing market conditions.

Based on an equal weighting of the three approaches, I determine the following best estimate for Alberta utility ROEs:

$$Ke = (1/3)(5.0) + (1/3)(6.9) + (1/3)(6.0) = \mathbf{6.0\%}$$

This estimate is very reasonable when compared to expected long-term overall stock market returns in the 5-9% range and a long-term expected market return of 7.0%, when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit “nominal” returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 5-9% range are consistent with current long-term forecasts by market professionals and with experienced long-term real stock returns. The ROE estimate is also consistent with our current low interest rate and low risk environment, which can be expected to change only gradually over the next few years.

4. CAPITAL STRUCTURE ISSUES

4.1. Background

4.1.1. Alberta Utilities' Operating Environment

Recent DBRS debt rating reports confirm previous similar statements noting low business risk as the #1 strength for Alberta operating utilities. For example, 2019 DBRS reports for EPCOR, Fortis Alberta and AltaLink, LP (as well as for AltaLink Investments, LP) all list "Low business risk" as the number 1 strength for these utilities. The number one strengths reported in reports for three other utilities echo this sentiment, with a slight variation in the wording. For ENMAX, the number 1 strength is listed as: "Low-risk regulated electricity operations in Alberta." For CU Inc., it is listed as: "Low-risk regulated businesses." Finally, for AltaGas Canada Inc., the #1 strength is listed as: "Stable cash flows underpinned by regulated utilities and contracted power assets."

These types of statements echo the sentiment in previous debt rating reports. For example, during the 2018 GCOC Proceeding, the utilities provided several debt rating reports, including 16 full reports that applied to Alberta operating utilities - nine from S&P (six – 2017; three -2016), and seven from DBRS (four – 2017; three – 2016). Eight of the nine S&P reports rate the respective utility as "Excellent" with respect to business risk, with the lone exception being the "Strong" business risk rating given to AltaGas for 2017. Four of the seven DBRS reports identified "low business risk" as the respective utility's #1 strength. For the other three: ENMAX's 2017 report suggested the #1 strength was "predictable, steady regulated business with growing earnings;"[57] CU Inc.'s 2017 report stated the #1 strength was that it was a "low-risk regulated business;"[58] and, AltaGas's 2017 report suggested the top two strengths were "Regulated and fee-based earnings with strong counterparties" and "Stable and diversified operations", respectively.[59] Similarly, during the 2016 GCOC Proceeding, all 15 rating reports for the Alberta utilities from calendar year 2015 refer to low

[57] Exhibit 22570-X0136, Appendix 3.4, DBRS Credit Rating Report for ENMAX Corporation, PDF page 2.
[58] Exhibit 22570-X0164, ATCO Utilities Credit Rating Reports, PDF page 21.
[59] Exhibit 22570-X0118, AUI MFR – Credit Rating Agency Reports, PDF page 11.

business risk as the #1 strength (in the case of DBRS reports) or rated the utilities as Excellent in terms of Business Risk (in the case of S&P reports).[60]

I concur with these assessments – regulated Alberta operating utilities possess low business risk.

In 2018, the utilities' experts argued that the performance-based regulation ("**PBR**") framework created additional risks for Alberta utilities (as they argued in the 2013 GCOC Proceeding), and that the 2018-2022 PBR framework created new challenges. Mr. Bell's 2018 evidence clearly refuted these arguments, as does his current evidence. In 2018, he showed that, since implementation, the return has increased and the standard deviation of returns has decreased during the PBR term for the PBR utilities. His current evidence confirms these results, both under PBR 1 and PBR 2. In effect, the PBR utilities did better than under cost of service ("**COS**"), and as such, the regulatory risk under PBR is actually less than under COS, resulting in lower business risk for PBR utilities. In 2018, Mr. Bell refuted suggestions that the 2018-2022 PBR framework will add significant new risk. The Commission supported these assertions in the 2018 GCOC Decision stating:[61]

> No persuasive evidence has been offered to support a conclusion contrary to those quoted above from Decision 20414-D01-2016 (Errata) and Decision 22394-D01-2018.
>
> Based on the foregoing, the Commission finds that there is no increase in business risk as a result of the 2018 to 2022 PBR plan.

Mr. Bell's current evidence notes that all relevant findings were well known by the time of the 2018 GCOC Decision, therefore "the findings related to PBR 2 and business risk in the 2018 GCOC apply in this proceeding."

The utilities also argued in 2018, as they did in the 2013 GCOC Proceeding and the 2016 GCOC Proceeding, that Decision 2013-417 (the "**UAD Decision**") created additional risk for Alberta utilities that warrants additional compensation. However, as in the prior proceedings,

[60] Technically, the Fortis Inc. January 5, 2015 report states that its # 1 strength is "strong and stable dividends from low-risk utilities", which is essentially the same as saying low business risk.
[61] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 115, para. 552 and 553.

they did not provide any tangible evidence to support this conjecture. In 2018, Mr. Bell refuted the entire notion that the utilities should receive compensation for the risk associated with potential losses, while at the same time being in position to realize any gains – it is simply not fair. In other words, in their discussion of the UAD Decision, the utilities did not account for the fact that the UAD Decision also holds the possibility that *gains* will accrue to shareholders, as noted in the 2013 GCOC Decision, where the Commission concluded:

> Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores Block* decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.
>
> In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.[62]

In the 2018 GCOC Decision, the Commission confirmed its stance in previous decisions that the UAD Decision has not materially increased business risk for Alberta utilities:[63]

> In conclusion, the Commission is not satisfied that there has been an increase in business risk for the affected utilities since the 2016 GCOC proceeding with regard to the UAD decision or the related issue of asset utilization.

Mr. Bell's current evidence confirms that since the time of the 2018 GCOC Decision "nothing has changed regarding the asset risk experienced by Alberta utilities."

Despite the arguments put forth by the utilities' experts during previous Proceedings, as noted above, Alberta utilities continue to be rated excellent with respect to business risk by S&P, while low business risk is the #1 strength in DBRS reports. This is what one would

[62] Decision 2191-D01-2015, 2013 Generic Cost of Capital, paras. 350-351.
[63] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 119, para. 577.

expect for mature regulated transmission and distribution utilities operating virtual monopolies in a supportive regulatory environment in which they are able to pass on legitimate costs to customers. My empirical analysis below confirms that Alberta utilities continue to operate in a low risk environment that enables them to consistently earn well above their allowed ROEs with very little volatility in these realized returns.

4.1.2. Economic Conditions and Alberta Utilities

Section 2 shows that global economic conditions are stable, and that Canadian economic and capital market conditions remain strong. Real GDP growth for Alberta is estimated at 2.4% in 2020 and 3.1% in 2021, well above the expected national averages of 1.7% and 1.8% respectively. Overall, we can say that the Canadian and Alberta economies are expected to grow at healthy levels in the intermediate term. In any event, economic and capital market conditions are similar to those existing during the 2018 GCOC Proceeding, have improved materially since the 2016 GCOC Proceeding, and are far removed from those existing at the peak of the 2008-2009 financial crisis.

It is important to note that regulated utilities are not as greatly influenced by economic cyclicality to the extent of traditional businesses. This is true of Alberta utilities. For example, in 2009, real GDP growth in Alberta was -4.1%, yet the average EBIT/Sales ratio for Alberta utilities was 29.1%, slightly above the 2005-2016 average of 28.9%. During 2009, the average ROE earned by Alberta utilities was 9.91% as reported in Table 15, which was 91 bp above the allowed ROE of 9.0%. Empirical evidence like this indicates that the earnings of Alberta utilities are resilient in the face of economic decline, which demonstrates the low risk nature of their businesses. I provide compelling evidence to support this conclusion in Sections 4.2 and 4.3.

4.2. A Quantitative Review of Alberta Utilities' Performance

A compelling way of reviewing the performance of Alberta utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities – "where the rubber hits the road," so to speak. Table 15 provides such a comparison of the reported ROEs by Alberta utilities in their Rule 005 reports with the allowed ROEs. The working papers for Tables 15 and 16 have been appended to my evidence as Exhibit N. The yearly average and median figures show that Alberta utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average reported ROE was a mere 0.18% below the allowed ROE, while the median equalled it. We get a similar message if we look at the weighted average ROE ("**Wt Av ROE"**). This is estimated by weighting each utility according to its average revenue over the entire 2005-2018 period, relative to total revenue across all utilities over the entire period, which effectively gives larger weight to the larger utilities.[64]

TABLE 15

ALBERTA UTILITIES REPORTED ROEs (2005-2018)

	2018	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**
Fortis Alberta	8.90%	9.32%	9.70%	11.12%	9.77%	9.49%	9.99%	9.73%	9.63%	9.13%	9.19%	8.79%	10.28%	10.45%
ATCO Elec Dist	8.21%	13.21%	13.03%	9.90%	9.74%	10.99%	12.14%	11.50%	12.57%	12.62%	10.27%	10.26%	9.38%	9.10%
ATCO Gas	11.03%	16.03%	12.93%	11.10%	10.95%	11.86%	11.01%	10.98%	9.67%	11.57%	11.67%	10.83%	8.26%	5.81%
AltaLink	7.72%	9.17%	8.21%	8.44%	8.44%	8.77%	9.28%	9.48%	9.10%	9.30%	8.50%	9.20%	9.40%	10.60%
ATCO Pipelines	10.42%	10.99%	11.39%	9.80%	10.31%	10.16%	11.16%	11.53%	10.85%	10.88%	9.51%	8.21%	10.61%	10.19%
ATCO Elec Trans	7.99%	9.96%	9.14%	8.23%	8.91%	9.84%	10.66%	9.87%	10.21%	9.63%	8.74%	8.50%	9.28%	9.61%
AltaGas	9.81%	9.37%	5.83%	6.16%	11.27%	12.50%	10.17%	6.19%	4.86%	8.94%	8.75%	8.51%	8.93%	9.50%
ENMAX Dist	6.53%	9.64%	9.93%	6.15%	7.82%	8.05%	10.22%	6.71%	6.79%	10.39%	8.27%	5.08%	6.99%	9.50%
ENMAX Trans	10.63%	10.90%	10.33%	11.48%	7.09%	5.90%	0.49%	4.08%	6.61%	12.84%	9.34%	6.58%	10.85%	
EPCOR Dist	10.81%	8.02%	8.98%	10.37%	10.31%	9.74%	8.10%	8.03%	10.76%	4.48%	7.81%	9.82%	8.85%	9.16%
EPCOR Trans	8.20%	5.76%	6.94%	8.90%	11.59%	7.17%	10.82%	8.36%	9.71%	9.20%	11.12%	10.47%		
Average	9.11%	10.22%	9.67%	9.24%	9.65%	9.50%	9.46%	8.77%	9.16%	9.91%	9.38%	8.75%	9.28%	9.32%
Median	8.90%	9.64%	9.70%	9.80%	9.77%	9.74%	10.22%	9.48%	9.67%	9.63%	9.19%	8.79%	9.33%	9.50%
Max	11.03%	16.03%	13.03%	11.48%	11.59%	12.50%	12.14%	11.53%	12.57%	12.84%	11.67%	10.83%	10.85%	10.60%
Min	6.53%	5.76%	5.83%	6.15%	7.09%	5.90%	0.49%	4.08%	4.86%	4.48%	7.81%	5.08%	6.99%	5.81%
StDev	1.50%	2.67%	2.25%	1.87%	1.45%	1.96%	3.15%	2.37%	2.23%	2.28%	1.20%	1.72%	1.15%	1.42%
CV(ROE)	0.165	0.262	0.232	0.202	0.150	0.206	0.333	0.270	0.243	0.230	0.128	0.196	0.124	0.153
Wt Av ROE	8.98%	11.17%	10.46%	9.50%	9.73%	10.17%	10.32%	9.69%	9.86%	10.03%	9.52%	9.18%	8.92%	8.70%
Allowed ROEs	8.50%	8.50%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%	9.00%	8.75%	8.51%	8.93%	9.50%
Diff Avg	**0.61%**	**1.72%**	**1.37%**	**0.94%**	**1.35%**	**1.20%**	**0.71%**	**0.02%**	**0.16%**	**0.91%**	**0.63%**	**0.24%**	**0.35%**	**-0.18%**
Diff Median	**0.40%**	**1.14%**	**1.40%**	**1.50%**	**1.47%**	**1.44%**	**1.47%**	**0.73%**	**0.67%**	**0.63%**	**0.44%**	**0.28%**	**0.40%**	**0.00%**
Diff Wt Avg	0.48%	2.67%	**2.16%**	**1.20%**	**1.43%**	**1.87%**	**1.57%**	**0.94%**	**0.86%**	**1.03%**	**0.77%**	**0.67%**	**-0.01%**	**-0.80%**

[64] The corresponding weights are reported in Table 16.

Table 16 provides the summary statistics for each utility over the period and aggregates them. These statistics show that ROEs averaged 9.38% across all utilities and all years, while allowed ROEs averaged 8.67%.[65] The last three rows in this table show that the annual averages of reported ROEs exceeded the allowed ROEs over the 14-year period by 0.72%, with the annual median ROEs exceeding allowed ROEs by a 14-year average of 0.86%. The weighted annual average ROE exceeds the allowed average by an even higher margin of 1.05%, indicating that the larger utilities have been better than average at earning above the allowed ROE. This shows that Alberta utilities operate in a low risk environment that enables them to earn attractive returns – i.e., since they are consistently able to earn their allowed ROEs or higher. This can be considered the **strongest indication that the utilities possess low risk overall**.

TABLE 16

SUMMARY STATISTICS – ALBERTA REPORTED ROEs (2005-2018)

	Revenue Avg. (05-18) Weight	**Average**	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Fortis Alberta	0.113	9.68%	9.67%	11.12%	8.79%	0.64%	0.066
ATCO Elec Dist	0.171	10.92%	10.63%	13.21%	8.21%	1.60%	0.147
ATCO Gas	0.172	10.98%	11.02%	16.03%	5.81%	2.27%	0.206
AltaLink	0.139	8.97%	9.14%	10.60%	7.72%	0.70%	0.078
ATCO Pipelines	0.059	10.43%	10.52%	11.53%	8.21%	0.87%	0.083
ATCO Elec Trans	0.118	9.33%	9.45%	10.66%	7.99%	0.78%	0.084
AltaGas	0.034	8.63%	8.94%	12.50%	4.86%	2.17%	0.252
ENMAX Dist	0.079	8.00%	7.94%	10.39%	5.08%	1.70%	0.213
ENMAX Trans	0.015	8.24%	9.34%	12.84%	0.49%	3.49%	0.424
EPCOR Dist	0.081	8.95%	9.07%	10.81%	4.48%	1.66%	0.185
EPCOR Trans	0.019	9.02%	9.05%	11.59%	5.76%	1.82%	0.202
Average		**9.38%**	9.52%	11.93%	6.13%	1.61%	**0.176**
Median		**9.02%**	9.34%	11.53%	5.81%	1.66%	**0.185**
Max		10.98%	11.02%	16.03%	8.79%	3.49%	0.424

[65] The last column in Table 16 reports a commonly used measure of volatility, the coefficient of variation (CV) – in this case, the CV of ROE – denoted as CV(ROE). The CV is determined by dividing the standard deviation (SD) of the ROE by the average ROE value. The rationale for using the CV as a measure of ROE volatility, rather than simply using the SD is that the SD is affected by the size of the average ROE. In other words, firms with larger ROEs would have higher SDs, even if they have less volatility, simply because the level of the ROEs figures used to determine the SD are higher.

Min	8.00%	7.94%	10.39%	0.49%	0.64%	0.066
StDev	1.02%	0.89%	1.66%	2.43%	0.86%	
Wt Av ROE	**9.72%**	9.69%	11.17%	8.75%	0.67%	
	Average	Median	Max	Min	StDev	
Allowed ROEs	**8.67%**	8.63%	9.50%	8.30%	0.35%	
Diff Avg	**0.72%**	0.67%	1.72%	-0.18%	0.56%	
Diff Median	**0.86%**	0.70%	1.50%	0.00%	0.53%	
Diff Wt Avg	**1.05%**	1.04%	2.67%	-0.75%	0.86%	

4.3. A Quantitative Assessment of Alberta Utilities' Risk

4.3.1. Business Risk

My examination of the Alberta utilities' operating and regulatory environment above suggests they possess low business risk. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great of an ability to flow through increases in their costs to their customers. As noted in Section 4.1, debt rating reports consistently suggest that the Alberta utilities have low business risk.

4.3.2. Comparing the Risk of Alberta Utilities to U.S. Utilities

The purpose of the analysis in this section is to provide quantitative evidence comparing the risk of U.S. utilities that have been previously used in the utilities' experts' evidence to that of the Alberta utilities. In particular, the evidence provided by the utilities has relied heavily on U.S. samples based on the premise that such samples are of comparable risk to Alberta utilities, and therefore require no adjustments for comparison purposes. While U.S. utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Alberta counterparts. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts, although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions.

One effective way to compare overall riskiness of Alberta utilities to their U.S. counterparts would be to compare their ability to earn their allowed ROEs, as I did for the Alberta utilities in Tables 15 and 16. Recall that Alberta utilities earned ROEs above the allowed ROEs on average every year from 2006 to 2018, and that over the entire period they earned ROEs that exceeded allowed ROEs by an annual average (median) of 0.72% (0.86%) with a revenue-weighted annual average of 1.05%. This is **bottom line empirical evidence** that Alberta utilities have low risk – i.e., "where the rubber hits the road."

Unfortunately, it is not practical for me to undertake a comprehensive comparison of the earned ROEs to allowed ROEs for U.S. utilities since most are primarily holding companies that own several distinct operating utilities, which operate in numerous jurisdictions. However, I can point to the 2018 GCOC evidence of Mr. Thygesen, which showed that the U.S. utilities he examined did *not* earn their allowed ROE on average.[66] For example, he found that over the 2014-2016 period the U.S. utilities included in Mr. Hevert's 2018 evidence earned on average 1.0% below their awarded ROE, with 64% of them earning below the awarded figure.

A recent Oliver Wyman report on North American utilities provides support for Mr. Thygesen's 2018 findings, suggesting that the "average utility does not earn its allowed return on equity."[67] Even stronger support for this conclusion can be found in the Azgad-Tromer and Talley (2017) empirical study referenced previously. This study examined allowed ROEs versus actual ROEs using observations from all 50 states as well as four Canadian provinces over the 2005-2016 period.[68] The study contained predominantly U.S. observations, with only 18 of the 544 observations being from Canada. Hence their finding that "awarded ROEs appear to overshoot realized ROEs by between 1.5 and 1.75 percent…" can be seen as an indication that U.S. utilities do not on average earn their awarded ROE. In fact, it seems they significantly fall short of doing so, with average (median) under-performance of 1.79% (1.45%) according to Figure 4 of their study. This contrasts

[66] Exhibit 22570-X0551, 2018 CCA Evidence of J Thygesen, para. 115-144.
[67] Source: Page 10 of "North America Utilities: Still a Smart Bet for the New Grid," Oliver Wyman, 2015. Appended to my evidence as Exhibit AY.
[68] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://www.semanticscholar.org/paper/The-Utility-of-Finance-Azgad-Tromer-Talley/c5913d92dc6600974956b13c9383bee6f61b731b).

significantly with the Alberta evidence provided in Tables 15 and 16, which showed that Alberta utilities consistently earned well above their awarded ROEs over the 2005-2018 period. Clearly, it is inappropriate to compare the two groups of utility firms, which amounts to comparing apples to oranges.

Aside from referencing these sources of evidence regarding U.S. utilities' ability to earn their awarded ROE, another effective way of comparing the riskiness of Alberta utilities to that of the U.S. utility proxy groups is to compare the volatility in earned ROEs. ROE volatility is a measure of total risk (i.e., business and financial risk), since financial leverage influences net income. In order to avoid debate over my U.S. sample selection during the 2016 and 2018 GCOC Proceedings, I used the same U.S. utilities for comparison purposes as those used by the utilities' experts. For example, in 2018, I cross-referenced 37 utilities used by Dr. Villadsen, Mr. Hevert and Mr. Coyne, and only included firms that were in at least one of their samples. This left me with 32 U.S. utilities. This sample included 18 of the 21 U.S. Electric Utility firms that Dr. Villadsen classified as regulated, 7 of the 9 U.S. Electric Utilities she classified as partially regulated, and 6 of the 9 utilities in her U.S. Gas sample – i.e., 31 of the 39 firms (i.e., 80%) she used in these samples. It also included 19 of the 25 U.S. utilities (i.e., 76%) used by Mr. Hevert, and 7 of the 11 U.S. utilities (i.e., 64%) used by Mr. Coyne. Hence it was a reasonable depiction of the U.S. utilities used by the utilities' experts. In my current evidence, I include the 29 of these 32 utilities for which data was available.[69]

Table 17 provides the summary statistics for earned ROEs for the U.S. sample over the 2009-2018 period, similar to those provided for the Alberta utilities in Table 16 over the 2005-2018 period. While the time periods differ slightly, Table 17 shows that the reported ROEs are similar for the U.S. utilities on average, with an average across all 29 utility averages of 9.31%, versus the corresponding figure of 9.38% across the Alberta utilities. However, if we look at the last column in Table 17 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the U.S. firms to the results in the last column of Table 16 for Alberta utilities, we can see that the U.S. utilities displayed greater volatility in ROEs than

[69] I was unable to find data for for three of them (Northwest Natural Gas Co., Scana Corp. and WGL Holdings Inc.).

the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the U.S. utilities were 0.277 and 0.229 respectively, versus corresponding figures of 0.176 and 0.185 for Alberta utilities as reported in Table 16.[70] While not reported in Table 16, the CV(ROE) for Alberta utilities averaged 0.180, with a median of 0.147 over the 2009-2018 period, which corresponds to the time period for the U.S. ROE stats. The working papers for Table 17 are appended to my evidence as Exhibit O.

TABLE 17

SUMMARY STATISTICS – U.S. REPORTED ROEs (2009-2018)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
ALLETE INC	8.27%	8.30%	9.13%	6.95%	0.57%	0.069
ALLIANT ENERGY CORP	9.95%	10.43%	11.68%	3.84%	2.28%	0.229
AMEREN CORP	5.32%	7.74%	11.00%	-13.40%	7.10%	1.333
AMERICAN ELECTRIC POWER CO	9.82%	10.12%	13.72%	3.46%	2.70%	0.275
ATMOS ENERGY CORP	10.34%	9.93%	13.90%	9.36%	1.38%	0.133
CENTERPOINT ENERGY INC	14.36%	13.13%	43.99%	-17.28%	16.74%	1.165
CMS ENERGY CORP	12.53%	13.42%	14.29%	8.22%	1.94%	0.155
CONSOLIDATED EDISON INC	9.15%	9.12%	10.26%	8.60%	0.51%	0.056
DOMINION RESOURCES INC	14.09%	14.21%	24.23%	2.74%	5.56%	0.394
DTE ENERGY CO	9.88%	9.72%	12.22%	8.48%	1.35%	0.136
EDISON INTERNATIONAL	6.50%	8.96%	15.43%	-3.82%	6.53%	1.004
EL PASO ELECTRIC CO	10.03%	9.47%	13.18%	7.31%	1.97%	0.196
ENTERGY CORP	7.76%	9.43%	15.26%	-6.73%	7.23%	0.932
FIRSTENERGY CORP	-3.66%	5.25%	18.39%	-66.20%	26.04%	-7.115
IDACORP INC	9.82%	9.78%	10.45%	9.21%	0.36%	0.037
MGE ENERGY INC	11.43%	11.28%	12.99%	10.41%	0.95%	0.083
NEW JERSEY RESOURCES CORP	13.53%	13.50%	17.58%	7.06%	3.33%	0.246
NEXTERA ENERGY INC	14.41%	13.04%	21.29%	11.19%	3.50%	0.243
NORTHWESTERN CORP	10.00%	9.73%	11.02%	9.36%	0.62%	0.062
OGE ENERGY CORP	12.62%	13.22%	16.97%	8.26%	2.42%	0.192
OTTER TAIL CORP	6.19%	9.65%	11.55%	-2.38%	5.58%	0.902
PG&E CORP	3.11%	7.65%	12.38%	-42.99%	16.34%	5.256
PINNACLE WEST CAPITAL CORP	8.92%	9.78%	10.00%	2.02%	2.45%	0.274
PNM RESOURCES INC	5.33%	6.37%	11.26%	-2.83%	3.86%	0.723
PORTLAND GENERAL ELECTRIC CO	8.03%	8.29%	9.38%	5.92%	1.06%	0.132

[70] The U.S. average is 0.367 if we leave out the two extreme values of -7.115 for FirstEnergy and 5.256 for PG&E.

PUBLIC SERVICE ENTRP GRP INC	12.92%	12.44%	19.23%	6.77%	3.53%	0.273
SOUTH JERSEY INDUSTRIES INC	9.50%	10.83%	14.95%	-0.32%	4.92%	0.517
SOUTHWEST GAS CORP	9.60%	9.36%	11.15%	8.18%	0.92%	0.095
XCEL ENERGY INC	10.11%	10.25%	10.65%	9.46%	0.40%	0.040
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**9.31%**	10.15%	14.74%	-0.32%	4.55%	**0.277**
Median	**9.82%**	9.78%	12.99%	6.77%	2.45%	**0.229**
Max	**14.41%**	14.21%	43.99%	11.19%	26.04%	5.256
Min	**-3.66%**	5.25%	9.13%	-66.20%	0.36%	-7.115
StDev	**3.76%**	2.19%	6.72%	16.88%	5.81%	1.726

Date Source: www.morningstar.ca

The ROE analysis above suggests that the U.S. utilities possess greater risk than Alberta utilities. This is hardly surprising given that the U.S. sample is comprised of holding companies with various ownership structures and a variety of exposures to risks (including significant generation risks) to which Alberta transmission and distribution operating utilities are not – at least not to the same extent. This is consistent with my discussion of beta estimation in Appendix B of my 2018 evidence, which addressed Mr. Hevert's historical evidence of Canadian and U.S. utility beta estimates. In particular, Charts 22 and 23 of Mr. Hevert's 2018 evidence showed that U.S. utility beta estimates consistently exceeded those of Canadian utilities, with long-term averages of 0.51 and 0.43, which were 34.2% and 26.5% higher than the corresponding Canadian weekly and monthly average estimates of 0.38 and 0.34. In fact however, this difference in Canada-U.S. beta estimates understates the true difference in risk, since the estimated betas are "levered" betas (i.e., they do not adjust for differences in the leverage ratios of the companies used to estimate them). The reason this is misleading is because U.S. utilities display higher levered betas, despite the fact they should be expected to have lower leverage ratios on average (i.e., since U.S. utilities have higher allowed equity ratios). Hence, we would expect them to have lower betas than their Canadian counterparts if they had the same level of business risk. The opposite finding provides strong evidence that U.S. utilities possess *greater* business risk than Canadian utilities, since they have lower financial leverage (and hence lower financial risk) on average than Canadian utilities. Appendix B showed that the true *comparable* U.S. beta historical averages of 0.61 (monthly) and 0.72 (weekly) are almost double the comparable Canadian beta estimates of 0.34 and 0.38, after accounting for leverage differences.

Given such evidence, it is was also not surprising that 17 of the 30 utilities included in Dr. Villadsen's 2018 U.S. Electric sample were rated in the BBB category (as well as 2 out of 9 utilities in her U.S. Gas sample). 14 of 25 utilities in Mr. Hevert's 2018 U.S. sample also fell in the BBB category, as did 3 of the 11 utilities in Mr. Coyne's U.S. sample. As mentioned, there was overlap in some of the firms in the utilities' experts' U.S. samples, and the net result is that 18 of the 32 firms examined in my 2018 U.S. sample had debt ratings in the BBB category. It is hardly surprising that my results above confirm that Alberta utilities possess lower risk than the U.S. utilities, as measured by lower volatility in ROE. As a result, I do not use U.S. samples in my analysis, since they are not good comparators in terms of the risks they possess.

4.3.3. Conclusions About Alberta Utilities' Risk Versus Comparables

The discussion above shows that U.S. holding companies are poor comparators for regulated Alberta utilities, since they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk. Given the significant issues with using U.S. comparables, I have used only Canadian utilities in my CAPM, DCF and BYPRP analyses, while recognizing their limitations. In particular, while using Canadian utilities is better than using U.S. utilities, they are also imperfect comparators, since public information is generally only available for holding companies and not for operating companies. Given the comparability issues involved, I note that I focused on the use of averages, index betas and long-term average Canadian utility beta estimates in arriving at a final beta estimate. Similarly, I used averages across the utilities in my DCF analyses to try and mitigate potential comparability issues, and more importantly I use my market DCF estimates (which I consider to be more reliable) as a reasonableness check on the results.

The most important conclusion that arises from my analysis in Sections 4.1-4.3 is that regulated Alberta utilities possess very low business risk. My quantitative analysis in

Sections 4.2 and 4.3 confirms this fact, which supports Mr. Bell's conclusions and reflects the long-standing business risk assessment of Alberta utilities by debt rating agencies.

4.4. Financial Risk and Credit Metrics

Section 4.3 shows that Alberta utilities have earned ROEs at or above their allowed ROEs for the last 13 years – exceeding them by an annual average of 0.72% (weighted average of 1.05%) over the 2005-2018 period. They have done so with very low volatility in these earned ROEs. These facts suggest that they possess low total risk, which is a function of both business risk and financial risk.

The allowed equity ratios ("**ERs**") in the 2018 GCOC Decision were 37% for all of the utilities, with the exception of the ER of 39% for AltaGas. During the 2018 Proceeding, the Commission considered credit metrics, as they have in previous proceedings. In terms of thresholds for these metrics, the Commission noted in the 2018 GCOC Decision that they would follow their 2016 process, stating:[71]

> In the 2016 GCOC decision, the Commission took guidance from the EBIT coverage ratio threshold used in the 2009 GCOC proceeding, in which the Commission observed that an EBIT coverage of 2.0 was the minimum threshold associated with regulated utilities with an A-range credit rating.
>
> In the 2016 GCOC decision, the Commission also placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using a "low volatility scale." The Commission noted that the credit metric benchmarks used by S&P for an A-range credit rating are an FFO coverage ratio of 2.0 to 3.0, an FFO/debt ratio of 9.0 per cent to 13.0 per cent, and an EBITDA coverage ratio of 2.5 to 4.0. The Commission did not focus on the EBITDA coverage ratio in the 2016 GCOC decision.
>
> In the 2016 GCOC decision, the Commission also calculated the deemed equity ratios that were required to attain the minimum credit metrics necessary to maintain an A-range credit rating for a typical taxable distribution utility, a typical non-taxable distribution utility, a typical taxable transmission utility and a typical non-taxable transmission utility. The Commission has performed the same calculations as part of this decision.

[71] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 141, para. 699, 700 and 701.

Mr. Bell's evidence shows that the EBIT coverage ratio, the FFO coverage ratio and the FFO/Debt ratios associated with an ER of 37% and at the existing ROE of 8.5% would be 2.42, 3.64 and 11.88% respectively. These ratios exceed the thresholds noted above by the Commission of 2.0, 2.0-3.0, and 9-13%, respectively, very comfortably. The equity ratio required to meet the EBIT coverage ratio threshold of 2.0, as well as the FFO coverage ratio of 2 or 3 are all below 30%. The equity ratio required to maintain an FFO/Debt ratio of 9.0 is also below 30%, while an equity ratio of 41% would be required to maintain a ratio of 13. Appendix B of Mr. Bell's evidence further shows that the metrics for Alberta utilities would exceed these minimum values if the ER was maintained at 37%, while the allowed ROE was reduced to 7.5% - with EBIT coverage of 2.25, FFO coverage of 3.51 and FFO/Debt of 11.31%.

Given my conclusions regarding the low risk possessed by Alberta utilities, the metric analysis above shows that the Commission can comfortably reduce the allowed ROE in combination with the existing equity ratio of 37%, and maintain the financial integrity of the utilities.

4.5. Capital Structure Recommendation

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility and their ability to consistently generate high profits. They have consistently generated ROEs above the allowed ROEs for the last 13 years consecutively, and these earned ROEs have displayed low volatility. My analysis of the global, Canadian and Alberta economies suggests that economic and capital market conditions are stable as they were during the 2018 Proceeding, which were improved relative to the 2016 GCOC Proceeding. The main difference in these conditions is that utility borrowing costs have declined significantly, by approximately 50 bp (to 3.0%). This decline is the result of a 0.50% decline in long-term government bond yields (to 1.7%), combined with no change in A-rated utility yield spreads, which remain at approximately 130 bp. I recommend that the Commission maintain existing allowed equity ratios, in combination with my recommended reduction in the allowed ROE. My risk analysis suggests this is a reasonable approach, and the credit metric analysis provided by Mr. Bell supports this position.

5. UTILITY YIELD SPREADS

Bond yield spreads, including A-rated utility yield spreads, fluctuate through time in response to a number of factors including general economic conditions, financial market performance, capital market uncertainty, and demand and supply conditions in the fixed income market. It is a combination of these factors that *explain* yield spreads. Unfortunately, *predicting* what these spreads will be is much more complicated, especially over short periods of time, similar to forecasting government yields or stock market returns and volatility.

The Commission has previously acknowledged the relationship between yield spreads and general risk perceptions, as in the 2018 GCOC Decision, when it stated:[72]

> 390. … Where utility bonds are used (as was done by Dr. Cleary, and Mr. Hevert in his rebuttal evidence) the bond yield also incorporates a credit spread, which the Commission in past GCOC decisions has accepted to be an objective measure that helps inform the Commission about investors' risk perceptions.

Figure 3 of my evidence confirms this relationship, showing clearly that these spreads widen during periods of greater market volatility and uncertainty. For example, Figure 3 shows that this spread peaked at 3.05% in December of 2008, around the peak of the 2007-09 financial crisis – about three times the long-term average of 1%. On the flip side, this spread sat at a low of 0.76% during a period of market stability in January of 2004. The current spread of 1.3% is the same as it was during the 2018 Proceeding, and is well below spreads of around 2% that existed at the time evidence was prepared during the 2016 GCOC Proceeding. This decline is consistent with stable economic and capital market conditions, including low volatility relative to long-term averages.

Yield spreads are analogous to the MRP that we use to estimate equity market risk premiums in the sense that it represents the price of risk in bond markets at a particular point in time (i.e., the spread is a risk premium). Unlike the MRP, which can never actually be observed and must be estimated, the yield spread is widely available to market participants, and it

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[72] Decision 2250-D01-2018, 2018 GCOC Decision, page 83, para 390.

represents a "market-determined" variable. This is why it is such an important statistic, especially when estimating the cost of equity to utilities, since it is a major component of their cost of debt (along with government yields). The Commission acknowledged this fact in the 2018 GCOC Decision, stating:[73]

> The Commission agrees with the view expressed by both Mr. Hevert and Dr. Cleary that an advantage of this method is that it incorporates readily observable, market-determined data such as bond returns and yields, which in turn can be deconstructed into the risk-free rate and credit spread components. The Commission observes that the credit spread component needed by utility bond investors is imbedded in the return to equity investors, along with some additional margin.

As noted in my 2016 and 2018 evidence, yield spreads and government yields tend to move in opposite directions, with government yields declining during periods of uncertainty, and yield spread tending to increase during such periods. In fact, the correlation coefficient between long-term government bond yields and A-rated utility yield spreads over the January 2003-January 2020 period was -0.47, which indicates a strong negative relationship – exactly as logic would dictate, and as I have previously argued. It is important to recognize that this is not an exact one-to-one relationship, but a general one. In fact, since the time of the 2018 Proceeding, we have seen government yields decline by about 50 bp, while the A-rated utility yield spread remained at 1.3%, resulting in a decrease in A-rated utility yields of approximately 50 bp. The bottom line is that the actual cost of debt is what is important, since it directly affects their cost of equity. This important fact is the reason why the BYPRP approach provides important, and arguably the most relevant, cost of equity estimates – because it is based upon an objectively market-determined cost of firm debt. This is also the reason why I recommend that any formula-based ROE mechanism (discussed in Section 6) should be based upon A-rated utility yields, and not just government yields.

[73] Decision 2250-D01-2018, 2018 GCOC Decision, page 82-83, para 389.

6. ANNUAL ROE FORMULA

6.1. Background

It is useful to provide some context regarding the use of an automatic adjustment mechanism ("**AAM**") to determine allowed ROEs, with reference to a starting point regarding awarded ROEs. The last time an AAM was used, was over the 2005-2008 period, subsequent to the 2004 GCOC Proceeding, which established an awarded ROE of 9.6% for 2004. As noted in Section 3.1, at the time, this ROE was 4.3% above long-term government yields (RF) of 5.3%, and was 3.5% above the A-rated utility yield of 6.1%. Decision 2004-052 (the 2004 GCOC Decision) described the mechanism that was implemented at that time:[74]

$$ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t - 5.68\%)]$$

where YLD_t = the forecast long-term Canada bond yield for year t.

> Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year *t* shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

Based on this formula, the allowed ROEs were set for 2005, 2006, 2007 and 2008 as 9.50%, 8.93%, 8.51% and 8.75% respectively.

Following the turbulent economic and capital market conditions that occurred during the 2007-2009 financial crisis period, in Decision 2009-216 (the "**2009 GCOC Decision**"), the Commission decided NOT to implement an AAM of any sort. At that time, the Commission noted:[75]

> The Commission accepts that the traditional relationships between Government of Canada 30-year bond rates and market equity returns did not continue through the

[74] Page 32 of Decision 2004-052, 2004 GCOC Decision, July 2, 2004.
[75] Decision 2009-216, 2009 GCOC Decision, page 108, para 417.

> entire period 2004 to the present. The Commission notes that between July 2008 and March 2009 the long Canada bonds rate declined more than 40 basis points. The Toronto Stock Exchange halved in value and the required market equity rate of return appears to have increased at the same time. Because of the way the formula had been designed, it was not capable of adjusting for the unexpected changes in the relationships that occurred in the capital markets, as a result of the financial crisis.

The 2009 GCOC Decision awarded an ROE of 9.0% for 2009 and 2010, and set 9% as the placeholder for 2011. Given that RF was 4.03% and A-rated yields were 5.43% at the date of this decision (November 12, 2009), the ROE-RF spread was 4.97% (0.67% above the 4.3% spread in 2004) and the ROE-A-yield spread was 3.57% (very close to the 3.5% spread in 2004). The Commission noted at the time that the ROE that would have been awarded using the AAM would have been 8.61%. This would have corresponded to an ROE-RF spread of 4.58% and an ROE-A-yield Spread of 3.18%.

In 2011, the Commission again rejected the notion of returning to an AAM approach to rate setting, stating in the 2011 GCOC Decision:[76]

> The Commission agrees with the interveners' arguments that a modified formula that accounts for changes in corporate bond spreads partially corrects for the drawbacks of a single-variable formula. Nevertheless, the Commission has considered the evidence of continuing credit market volatility and finds that a return to the formula mechanism for annual adjustments to ROE is not warranted at this time.

The 2011 GCOC Decision awarded ROEs of 8.75% for both 2011 and 2012, down 0.25% from the 2009-2010 rates. At the time of the Decision (December 8, 2011), RF had declined markedly (by almost 1.5%) to 2.58% and the A-rated yield had declined by about 0.8% to 4.18%, so the ROE spreads widened considerably at that time (by more than 1%), with an ROE-RF spread of 6.17% and an ROE-A-yield spread of 4.57%.

[76] Decision 2011-474, 2011 GCOC Decision, page 30, para 165.

The Commission provided similar reasons for rejecting the return to an AAM in the 2013 GCOC Decision, and also noted the low interest rate environment as a consideration impacting this decision:[77]

> 411. … In Section 4 of this decision, the Commission observes that the risks in the financial markets have moderated since Decision 2011-474. However, it also considers that in the current environment of historically low interest rates, market conditions may not be reflective of a typical risk-return relationship for an investor. This is important in the current case because one of the components of the proposed two-part formula tracks changes in government long-term bond yields. Accordingly, the Commission finds that an abnormal risk-return relationship triggered by ultra-low interest rates would be a valid concern, if such a formula was to be implemented for this test period.
>
> 412. The Commission notes that submissions from all parties regarding the use of an ROE formula included suggestions for the incorporation of "safety valve" hearings, reviews, or other reopener mechanisms to ensure proper operation of any adopted formula, given the economic conditions prevailing at a particular time. The Commission agrees that the institution of such mechanisms as part of an AAM are reasonable and that, furthermore, the desirability of such controls provides additional support for the idea that correct operation of AAMs such as ROE formulae are dependent on prevailing market conditions falling within a range of normalcy.
>
> 413. The Commission notes that both Ms. McShane and Dr. Booth recommended against use of an ROE formula until the government of Canada long-term bond yield exceeds 4.0 per cent. The Commission notes that as of the close of record of this proceeding, the long-term Canada bond yield is well below 3.0 per cent.
>
> 414. For the above reasons, the Commission will not reintroduce the use of an ROE formula or other AAM at this time. The Commission is prepared to revisit the

[77] Decision 2191-D01-2015, 2013 GCOC Decision, page 83, para 411-414.

> desirability of an ROE formula as part of future GCOC proceedings if its adoption would be warranted in light of the market conditions present at that time.

The 2013 GCOC Decision reduced the awarded ROE from the previous 8.75% to 8.3% for 2013, 2014 and 2015, and on an interim basis for 2016. At the time of the Decision (March 23, 2015), RF had declined further to 1.95% and the A-rated yield did as well to 3.35%, resulting in a further widening of both the ROE-RF spread to 6.35% and the ROE-A-yield spread to 4.95%.

The Commission did not formally review the possibility of using an AAM during the 2016 GCOC Proceeding, but did not return to the practice. During the 2018 GCOC Proceeding, the Commission once again did not implement an AAM, but noted in the 2018 GCOC Decision that:[78]

> Based on the evidence regarding market conditions in this proceeding, as summarized in Section 6, the Commission considers that returning to an annual adjustment/generic formula approach to ROE may be reasonable. Specifically, it would appear, based on the evidence in this proceeding, that the reasons justifying a departure from the annual adjustment formula in 2009 may no longer be a concern.

The 2016 GCOC Decision increased the awarded ROE from the previous 8.3% to 8.5%, and the 2018 GCOC Decision maintained the awarded ROE at 8.5%. At the time of the 2016 Decision (October 7, 2016), RF had declined slightly to 1.82% and the A-rated yield increased slightly to 3.51%, resulting in an ROE-RF spread of 6.68% and an ROE-A-yield spread of 4.99%. Finally, at the time of the 2018 Decision (August 2, 2018), RF had increased to 2.38% and the A-rated yield had increased to 3.76%, resulting in an ROE-RF spread of 6.12% and an ROE-A-yield spread of 4.74%.

6.2. Recommendation

I do **NOT** recommend the implementation of an AAM at this point in time for the following reasons:

[78] Decision 2250-D01-2018, 2018 GCOC Decision, page 83, para 411-414.

1. Government yields and A-rated utility yields are both near all-time lows at 1.7% and 3.0% respectively. Implementing a formula at this time would contradict the rationale used by the Commission in previous Proceedings for not implementing one. For example, as noted above in the 2013 GCOC Decision the Commission stated:[79]

    > "the Commission finds that an abnormal risk-return relationship triggered by ultra-low interest rates would be a valid concern."

    In that same Decision, the Commission also stated:[80]

    > The Commission notes that both Ms. McShane and Dr. Booth recommended against use of an ROE formula until the government of Canada long-term bond yield exceeds 4.0 per cent. The Commission notes that as of the close of record of this proceeding, the long-term Canada bond yield is well below 3.0 per cent.

    It is noteworthy that at the time of this Decision (March 23, 2015), long-term government yields and A-rated utility yields were sitting 1.95% and 3.35%, 0.25% and 0.35% "above" today's yields. Therefore, if we apply that rationale to today's environment, nothing has changed. If anything today's environment is an even more "ultra-low" interest rate environment, and clearly government yields are nowhere near 4%.

2. Related to the fact that yields are near all-time lows, the current spreads between allowed ROEs and government yields and A-rated utility yields are near all-time highs, presently sitting at about 6.8% and 5.5% respectively. As discussed in Section 3.1, these spreads are 2.5% and 2% above the corresponding spreads in 2004 of 4.3% and 3.5%, and are also well above the 2004-2019 averages of 5.5% and 4.1%. The implications of this are twofold:

[79] Decision 2191-D01-2015, 2013 GCOC Decision, page 83, para 411.
[80] Decision 2191-D01-2015, 2013 GCOC Decision, page 83, para 413.

a) Any mechanism that ties the ROE to levels of government bond yields and/or A-rated utility yields would essentially "*lock in*" these above average spreads.

b) Given that government yields and A-rated utility yields are near all-time lows, it is highly probable that such a mechanism would NOT produce symmetric results. In other words, it is much more likely that allowed ROEs would increase using such a mechanism than that they would fall. Further, any declines would be more limited in magnitude than would increases, since it is unlikely that RF and A-yields can decline much further.

Combining the implications of a) and b) above suggests that any AAM linked to RF and/or A-yields would lead to a continuation of excessive ROE spreads versus utility debt costs, with no opportunity to narrow this gap.

6.3. Possible AAM Mechanism

While I highly recommend that no AAM be implemented at this time for the reasons articulated in Section 6.2, I provide some comments below regarding a suitable approach to implementing an AAM under more appropriate conditions.

Consistent with my recommendations regarding an AAM in 2013, I would not support the use of such a mechanism over long periods of time. If implemented, subject to satisfying the trigger requirement described below, such a mechanism could be useful for establishing ROEs in the interim period between regulatory proceedings that would be required at regular intervals to provide a more comprehensive review of existing market conditions.

In order to avoid locking in an abnormally high ROE-A-yield spread and/or providing asymmetric recommendations, as discussed in Section 6.2, I do not recommend an AAM be implemented until the following condition is satisfied at the time an allowed ROE is established at a GCOC Proceeding:

- The A-rated utility yield is 3.8% or higher.

This precludes the use of such a mechanism during the current Proceeding, since they are currently at 3% and it is highly unlikely A-rated utility yields will reach this level by the close of the Proceeding.

The rationale for choosing 3.8% is that it is the median (and also the average) A-rated utility yield over the 2012-2019 period, which means that half of the time yields were higher than this rate, and half the time they were below it. Excluding observations over longer historical periods that had higher prevailing yields that are unlikely to rematerialize in the immediate future seems reasonable. For example, the A-rated utility yields averaged 5.65% over the pre-crisis 2004-07 period, 5.86% during 2008-09, and 4.99% over the subsequent 2010-11 period. These averages are high, and are unlikely to be observed again in the foreseeable future as they represent periods of higher interest rates in general than during our current environment (i.e., 2004-07), and periods of well above average volatility (2008-09 and 2010-11). Since 2012, A-rated utility yields have not returned to these levels, with a maximum over the period of 4.76%, a 90th percentile of 4.24%, and with 50% of the observations falling below 3.8%.

This constraint addresses the Commission's previously noted concerns about using an AAM during a period of ultra-low interest rates. It is similar in nature to the recommendations of Dr. Booth and Ms. McShane that was noted in the 2013 GCOC Decision; although it reflects the reality that the 4% government yield cut-off value they advocated is unlikely to be seen in the foreseeable future. It is also based on A-rated utility yields, and therefore reflects levels of both government yields and yield spreads.

Subject to the qualifications noted above, I believe that an appropriate AAM would incorporate both government yields (RF) and A-rated utility spreads, since it is the combination of these factors that determines utilities' cost of debt financing, as discussed in Section 2.1.2, Section 3.4 and in Section 5. This is because the cost of equity to utilities, as measured by ROE, is directly related to their cost of debt, which is a function of both factors. Incorporating both of these factors into an AAM has previously been advocated by experts representing both the utilities and interveners, and the Commission has expressed support for this approach. For example, in the 2011 GCOC Decision, the Commission stated:[81]

> All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula.

The Commission also provided support for such an approach in the 2013 GCOC Decision, stating:[82]

> The Commission observes that all three expert witnesses recommended that, if an ROE formula was to be adopted, it should incorporate the two elements: changes in government bond yields, and changes in utility bond spreads. In Decision 2011-474, the Commission agreed that this type of a formula has advantages over the single-variable formula, as it is likely to better reflect any fluctuations in capital market conditions.

I concur with the Commission's guidance in previous decisions, as I believe it is important to consider both factors that influence utilities' cost of debt. As a result, if the Commission does decide to implement an AAM, I would recommend the following mechanism at a future GCOC Proceeding when A-rated utility yields are 3.8% or higher (i.e., my criteria for using an AAM):

The allowed ROE would be determined based on the following formula:

$$ROE = ROE(base) + [0.75 \times (\text{A-yield}_{\text{Nov 30}} - \text{A-yield}_{\text{base}})]$$

Where,

ROE(base) = Allowed ROE set at the last Proceeding;

[81] Decision 2011-474, 2011 GCOC Decision, page 30, para 164.
[82] Decision 2191-D01-2015, 2013 GCOC Decision, page 83, para 410.

$A\text{-yield}_{Nov30}$ = the A-rated utility yield obtained from Bloomberg as of November 30th in the year prior to which the automatic allowed ROE would apply; and,

$A\text{-yield}_{base}$ = A-rated utility yield obtained from Bloomberg at the date at which the initial allowed ROE is set.

For example, assume the allowed ROE was initially set at 7.5% (ROE(base)) at a time when the A-rated utility yield was 4% ($A\text{-yield}_{base}$) – say for 2023. Since the A- rated utility yield is greater than 3.8%, the Commission could implement the AAM, assuming there are no other reasons not to do so. Assuming the Commission implemented the AAM in a 2023 GCOC Decision, with an initial allowed ROE of 7.5% for 2023. If A-rated utility yields had increased to 4.4% as of November 30, 2023, then the allowed ROE for 2024 would equal:

$$ROE = 7.0 + [0.75 \times (4.4 - 4.0)] = 7.5 + 0.3 = 7.8\%$$

This mechanism is an adaptation of the previous formula, which used 75% of government yield changes, that were based on government yield Consensus Forecasts. Given the evidence provided previously regarding the inaccuracy of such Consensus forecasts, it seems prudent to simply use the prevailing rates, which are likely to be more accurate predictions of future rates, and in any event represent the actual prevailing level of interest rates at the time. Secondly, using A-rated utility yields rather than simply government yields "simultaneously" incorporates the impact of both government yields and yield spreads. This is because the A-rated utility yield can be decomposed as the sum of these two components, as shown below:

A-Rated utility yield = 30-year government bond yield + A-rated utility yield spread

Thus, using A-rated utility yields at a particular point in time is easy to implement, and more importantly, it adequately reflects utilities' actual cost of debt, since it is a function of both government yields (i.e., interest rate levels) and yield spreads. These two factors tend to go in opposite directions, as discussed in Section 5. Using the resulting cost of debt to utilities' therefore reflects how the changes in each of these variables is offset by changes in the other variable.

I would recommend that the Commission consider reviewing, modifying or suspending the AAM if the following condition occurs while the AAM is in place:

- A-rated utility yield spreads exceed 2%.

The existence of A-rated yield spreads greater than 2% would be indicative of a period of extreme uncertainty in Canadian capital markets. For example, over the January 2003-January 13, 2020 period, the average A-rated yield spread was 1.37%, with a maximum of 3.05% during December 2008, which was at the height of the financial crisis. However, for the most part, these spreads fluctuated but did not approach such levels again. In fact, the 95th percentile for the spread over this period was 1.94%, and 2.01 represents the 95.5th percentile, and the spread has only exceeded 2% between October 2008 and June 2009, and briefly over the January-March 2016 period. This evidence suggests that a spread exceeding 2% indicates extreme capital market uncertainty, which is the kind of conditions in which an AAM might not work as desired – as previously indicated by the Commission. While this may not warrant suspension of the AAM, at minimum, it warrants a thorough review of existing capital market conditions at that time before continuing to use the recommendations of the AAM.

Finally, I do not recommend any corresponding adjustments to allowed equity ratios in conjunction with an AAM for setting allowed ROEs. Allowed equity ratios should be established at regular GCOC proceedings based on assessment of utility risk at that time.

6.4. Back-Testing Evidence

The Commission requested information regarding back-testing in this Proceeding. Even though, I do not support implementing an AAM at this point in time, as discussed above, I have performed back-testing of the version of an AAM that I would recommend implementing once my proposed trigger mechanism is satisfied. I provide these results in Table 18 below. The worksheet for Table 18 is appended to my evidence in Exhibit P.

TABLE 18

AAM MODEL – BACK-TESTING RESULTS (2004-2020)

Date	Allowed ROE	AAM Reset at Actual GCOC	AAM Reset every 4 years
2004	**9.60**	**9.60**	**9.60**
2005	9.50	9.49	9.49
2006	8.93	8.81	8.81
2007	8.51	8.70	8.70
2008	8.75	9.08	9.08
2009	**9.00**	**9.00**	**9.00**
2010	9.00	7.93	7.93
2011	**8.75**	**8.75**	7.65
2012	8.75	8.26	7.16
2013	**8.30**	**8.30**	**8.30**
2014	8.30	8.90	8.90
2015	8.30	8.37	8.37
2016	8.30	8.54	8.54
2017	**8.50**	**8.50**	**8.50**
2018	8.50	8.25	8.25
2019	8.50	8.59	8.59
2020	8.50	7.83	7.83
Average	8.71	8.64	8.51
Median	8.51	8.59	8.54
Max	9.60	9.60	9.60
Min	8.30	7.83	7.16
StdDev	0.40	0.49	0.64
Correlation with Allowed ROE		0.63	0.45

Table 18 provides two slightly different versions of AAM results. The first AAM column implements the ROE adjustment formula described above, and "resets" at every Proceeding that actually took place. The second AAM column assumes that the ROE would work for the three years following a Proceeding that established an allowed ROE. In essence the only difference between the two series is that the first column "resets" the ROE to 8.75% in 2011 at that GCOC Proceeding which occurred two years after the 2009 Proceeding, while the second column ignores this "reset" value for ROE, and does not reset until after four years have passed (i.e., at 2013). Comparing the first AAM column to actual ROEs we can see a similar average (i.e., 8.64% versus 8.71%) and median (8.59% versus 8.51%), with slightly more volatility, as would be expected (i.e., since the numbers are adjusted annually). Given that the ROEs were reset at the times of actual Proceedings, of which there were 5 over this 17 year period, this implies 12 years in which the numbers could potentially differ from the actual prescribed ROEs. Of those 12 years, the AAM prescribed ROE was higher than the actual ROE in 6 years, and was below it in the other 6 years.

The only difference in the second AAM column results is that the AAM recommended ROE for 2011 and 2012 were 7.65% and 7.16%, since this column ignores the 2011 ROE reset to 8.75%. As a result, the average and median of this series is lower than for the first AAM column at 8.54% and 8.51% respectively, and the series has a higher standard deviation as a result.

This concludes my testimony.

Attachment 5: Alberta GCOC proceedings in 2022-23 (AUC Proceeding ID 27084)

ALBERTA UTILITIES COMMISSION

2023 GENERIC COST OF CAPITAL

PROCEEDING ID #27084

EVIDENCE OF DR. SEAN CLEARY, CFA, PROFESSOR OF FINANCE

Submitted on behalf of:

The Office of the Utilities Consumer Advocate

February 1, 2023

TABLE OF CONTENTS

1 INTRODUCTION

1.1 Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am a Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta (the "**UCA**") on several occasions including generic cost of capital ("**GCOC**") proceedings in 2013-2014 (Proceeding ID 2191), 2015-2016 (Proceeding ID 20622), 2018 (Proceeding ID 22570), and 2019-20 (Proceeding ID 24110), as well as the generic regulated rate option proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan proceeding (Proceeding ID 22357) in 2017. I also prepared evidence on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016, and in 2018.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of 30 publications. My work has been cited more than 5,000 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of equity issues. I have authored or co-authored 14 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Appendix A to my evidence.

1.2 Purpose of Testimony

With respect to the 2023 GCOC Proceeding (Proceeding 27084) in Alberta, the UCA has requested that I provide recommendations regarding the appropriate return on equity ("**ROE**") and equity ratios for Alberta utilities, and provide recommendations regarding an annual ROE formula. I acknowledge that I have a duty to provide opinion evidence to the Alberta Utilities Commission (the "**Commission**" or "**AUC**") that is fair, objective and nonpartisan.

1.3 Summary of ROE Estimates

Several approaches were used to estimate the appropriate generic ROE for Alberta utilities including the Capital Asset Pricing Model ("**CAPM**"), Discounted Cash Flow ("**DCF**") and Bond Yield Plus Risk Premium ("**BYPRP**") models. Based on an equal weighting of these three approaches, I determined the following best estimates for an appropriate ROE:

CAPM (1/3rd)	**DCF (1/3rd)**	**BYPRP (1/3rd)**	**Best Estimate**
5.7%	7.13%	7.43%	**6.75%**

The details of all estimates are provided herein, as is the reason for choosing an equal weighting scheme.

This estimate is 75 basis points ("bp") above my 2020 estimate, provided in Commission Proceeding 24110 and 45 bp above my 2018 estimate, provided in Commission Proceeding 22570, which reflects increases in 30-year government bond yields and A-rated utility yields since those previous proceedings. It is a very reasonable estimate when compared to current expectations of market professionals for long-term overall stock market returns in the range of 6-9%, with a best estimate of 7.2% (or 7.7% if we added 0.50% for flotation costs as I did for the 6.75% estimate above), when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given long-term 2% inflation expectations and long-term real growth expectations around 2.0%.

1.4 Summary of Comments on Capital Structure

My analysis shows that Alberta utilities possess low risk as shown by their consistent "low business risk" ratings, their low earnings volatility, and most importantly, their ability to generate earned ROEs above the allowed ROEs for the last 17 years, having exceeded the allowed ROE by an annual average (weighted average) of 0.81% (1.12%) over the 2005-2021 period. My analysis also shows that these earned ROEs displayed very low volatility, indicating low total risk.

In this proceeding, I am recommending no change in allowed equity ratios, but rather emphasize the impetus for a reduction in the allowed ROE, which continues to be well above the actual cost of equity for Alberta utilities. My analysis suggests these recommendations are reasonable, and the credit metric analysis provided by Mr. Bell supports this recommendation.

1.5 Summary of Responses to Questions Posed in the "Issues List"

Formulaic approach to determine ROE[1]

The two-factor formula that will inform the Commission's questions can be expressed as follows:

ROE (test year) = Notional ROE plus Factor One plus Factor Two

Factor One: VAR4 x (Forecast Long Canada Bond Yield (test year) (VAR2) - Base Forecast Long Canada Bond Yield (VAR1))

Factor Two: VAR7 x (Utility Bond Spread (test year) (VAR6) – Base Utility Bond Spread (VAR5))

As discussed in Section 3, my recommended initial ROE is **6.75%**. In Section 5, I provide my recommended formula for an automatic adjustment mechanism ("**AAM**") for determining allowed ROEs, which is:

ROE = ROE(base) + [0.75 × (GoC 30-year (Nov 30) – GoC yield (base)]

+ [0.75 × (A-yield spread (Nov 30) – A-yield spread (base)]

As such, my recommendations for the various factors above are as follows:

VAR1: Base Forecast Long Canada Bond Yield:

Use the actual prevailing 30-year government bond yield at the time the initial (or base) ROE is set, based on the strong empirical support provided in Section 2.1.2 that actual

[1] For presentation purposes, I have highlighted, italicized and single-spaced the passages and questions incorporated from the Commission's November 29, 2022 "Issues List" document, and left my responses not italicized with 1.5 spacing.

yields are significantly superior to forecasts using Consensus forecasts (for example) plus estimates of the spread between 30-year and 10-year government yields. For example, as of January 19, 2023 the yield was 2.85%, so for illustration purposes, I will use this as the initial yield.

VAR2: Forecast Long Canada Bond Yield for Test Year:

Use the actual prevailing 30-year government bond yield as of November 30th in the previous calendar year, based on the strong empirical support provided in Section 2.1.2 that actual yields are significantly superior to forecasts using Consensus forecasts (for example) plus estimates of the spread between 30-year and 10-year government yields.

VAR3: Base Forecast ERP:

Using my ROE recommendation of 6.75% and the 2.85% 30-year government bond yield noted above, suggests that VAR3 = 6.75% - 2.85% = 3.9%

VAR1 + VAR3: Notional ROE:

As noted above my recommended ROE is 6.75% which = 2.85% (VAR1) + 3.9% (VAR3)

VAR4: Long Canada Bond Yield Adjustment Factor expresses the relationship between changes in the Forecast Long Canada Bond Yield and the forecast ERP for the Test Year. That is, for every 100-basis point change in the Forecast Long Canada Bond Yield for the Test Year versus the Base Forecast Long Canada Bond Yield, the ROE for the Test Year changes by VAR4 and the implied forecast ERP for the Test Year changes by (1 – VAR4):

As noted in my recommended AAM formula above, and discussed in Section 5, I recommend an adjustment factor of 0.75 be applied against annual changes in 30-year government bond yields.

VAR5: Base Utility Bond Spread:

> Use the actual prevailing A-rated utility yield spread at the time the initial or base ROE is set. For example, as of January 19, 2023 the A-rated utility yield was 4.43% while the 30-year government bond yield was 2.85%, so the A-rated yield spread was 1.58%. For illustration purposes, I will use this as the initial yield spread.

VAR6: Utility Bond Spread for Test Year:

> Use the actual prevailing A-rated utility yield spread as of November 30th in the previous calendar year, as discussed in Section 5.

VAR7: Utility Bond Spread Adjustment Factor expresses the relationship between changes in the Utility Bond Spread and the forecast ERP for the Test Year. That is, for every 100-basis point change in the Utility Bond Spread versus the Base Utility Bond Spread, the ROE for the Test Year changes by VAR7 and the implied forecast ERP for the Test Year changes by (1 – VAR7).

> As noted in my recommended AAM formula above, and discussed in Section 5, I recommend an adjustment factor of 0.75 be applied against annual changes in the A-rated utility yield spread.

Additional Questions in the Issues List:

Estimating VAR1: Base Forecast Long Canada Bond Yield
Question

1. What forecast long Canada bond yield and term to maturity should be used to specify the Base Forecast Long Canada Bond Yield? Why?

> Use the actual prevailing 30-year government bond yield at the time the initial or base ROE is set, based on the strong empirical support provided in Section 2.1.2 that actual yields are significantly superior to forecasts using Consensus forecasts (for example) plus estimates of the spread between 30-year and 10-year government yields.

2. Should the term to maturity of the base Forecast Long Canada Bond Yield be the same as that used to estimate VAR2? Why?

Yes – this is by definition when using the actual yields as I have recommended. But should also be the case even if forecasts were to be used.

Estimating VAR2: Forecast Long Canada Bond Yield for Test Year Questions

1. Does this approach remain appropriate? If so, why?

No – this approach is not appropriate, based on the strong empirical support provided in Section 2.1.2 that actual yields are significantly superior to forecasts using Consensus forecasts (for example) plus estimates of the spread between 30-year and 10-year government yields.

2. If not, why not? What alternative method should be used?

This approach is not appropriate, based on the strong empirical support provided in Section 2.1.2 that actual yields are significantly superior to forecasts using Consensus forecasts (for example) plus estimates of the spread between 30-year and 10-year government yields. Actual prevailing yields as of November 30th each year should be used instead, as discussed in Section 2.1.2 and in Section 5.

Estimating VAR3: Base Forecast ERP Questions

1. What is the forecast ERP for each of the utilities in the comparator group of utilities identified in the technical conference, using CAPM, DCF, multi-stage DCF, and a multifactor regression model?

(a) What is the forecast ERP for each of the utilities in the comparator group of utilities identified in the technical conference using bespoke or alternative methods, such as a Predictive Risk Premium Model or total market approach Risk Premium Model, to estimate cost of equity capital?

2. What are the key input variables for each calculation? How were they selected? Have input variables been selected to increase the statistical significance and/or result in higher coefficients of determination for the resulting analysis? Are variables directionally consistent with the level of forecast interest rates?

3. What adjustments, if any, have been made to any of the key input variables? For example, in the case of CAPM, are forecast ERPs calculated using adjusted betas that reflect a correction for mean reversion? Are adjustments empirically based?

4. Are forecast ERP results statistically significant, and do models have high coefficients of determination?

The answers to these questions can be found in Section 3 of my evidence, which discusses the three approaches I use to estimate the cost of equity ("**Ke**") of 6.75% for Alberta operating utilities, which corresponds to my recommended initial allowed ROE recommendation. Section 3 describes the three models in detail, any adjustments to the model inputs, and Ke estimates for the samples used. Section 3 also verifies the validity of my Ke estimate by making reference to market-determined Price-to-Book ratios for the utility samples.

Determining comparability of representative utilities
Questions

1. What factors could affect the degree of comparability of a utility and warrant a discounted weighting of their empirical ERP results?

Sections 3.2.4, 4.3.2 and 4.3.3 provide strong support for the assertion that U.S. utilities do **not** represent reasonable comparators to Alberta operating utilities since they possess significantly greater risk. I would note that while I do not consider U.S. utilities to be reasonable comparators and hence assign a zero weight to the results obtained from this sample, using the U.S. results would not have had any significant impact on my ROE estimates, and if anything, using them would have led me to a lower DCF estimate of Ke.

2. Based on the response to question 1, does the Commission have sufficient empirical data to render an informed decision consistent with the generic nature of this proceeding?

Yes. Please refer to the evidence provided in Sections 3.2.4, 4.3.2 and 4.3.3 which provide strong support for the assertion that U.S. utilities do **not** represent reasonable comparators to Alberta operating utilities since they possess significantly greater business risk.

Estimating Factor One: VAR4 - Long Canada Bond Yield Adjustment Factor
Question

1. What is the relationship between changes in the forecast Long Canada Bond Yield and the forecast ERP? Is this relationship sustainable, and is it statistically significant, with a high coefficient of determination?

I recommend an adjustment factor of 0.75, as discussed in Section 5. This maintains the relationship, but also reduces year-to-year fluctuations in allowed ROEs.

Estimating Factor Two: VAR7 – Utility Bond Spread Adjustment Factor Questions

1. Is this factor needed? Why or why not?

Yes. To minimize volatility in allowed ROEs from year to year.

2. If this factor were to be adopted for use:

(a) What data source should be used?

Assuming the question refers to where to obtain A-rated utility yields and the corresponding yield spread, the source would be Bloomberg – November 30th of every calendar year.

(b) What bond term to maturity should form the basis of the Utility Bond Spread factors?

The long-term yield, as has been used in the past, and to be consistent with the use of the long-term government bond yields in determining the yield spread.

(c) Should only A-range rated Utility Bonds be used, consistent with the Commission's approach on Capital Structure?

Yes. It also makes the data available (via Bloomberg) – the same data as has been used during previous proceedings.

(d) How should the Base Utility Bond Spread be calculated?

As noted above, use the actual prevailing A-rated utility yield spread at the time the initial or base ROE is set. For example, as of January 19, 2023 the A-rated utility yield was 4.43% while the 30-year government bond yield was 2.85%, so the A-rated yield spread was 1.58%.

(e) How should the Utility Bond Spread for the Test Year be calculated?

(f) When should the Utility Bond Spread for the Test Year be calculated?

As noted above, use the actual prevailing A-rated utility yield spread as of November 30th in the previous calendar year, as discussed in Section 5.

3. What is the relationship between changes in Utility Bond Spreads and Forecast ERP? Is this relationship sustainable, and is it statistically significant, with a high coefficient of determination?

The relationship can vary through time, and the real determining factor is the actual A-rated utility yield, which affects Ke, as discussed in my bond yield plus risk premium analysis in Section 3.4. For example, an increase in the yield spread (say 0.3%) could be more than offset by a greater decline in the risk-free rate (say 0.5%), which would result in a lower A-rated utility yield. This would generally imply a decline in Ke.

Other formulaic approaches and financial markets relationships
Questions

1. Are there other approaches or formulas the Commission should consider to mechanistically determine ROE on an annual basis? If so, what are these approaches?

No – as discussed in Section 5.

2. If so, what financial relationships would require specification to enable the use of this approach?

3. Are these relationships sustainable and statistically significant with a high coefficient of determination?

4. Is the data required to implement and annually update this approach readily available? If not, what data sources would be required?

5. Are there any other financial metrics that have a sustainable and statistically significant relationship to ERP? If so, what is the metric and the nature of the relationship. Should this metric be considered as a third factor in the two-factor formula considered in this issues list?

Questions 2 through 5 are not applicable, given my response to Question 1.

ROE formula update process
Question

1. What process should the Commission adopt to annually calculate the ROE using the formulaic approach that may result from this proceeding and make those results available to the public?

Update the ROE using data as of November 30th every year, as discussed in Section 5.

Determination of deemed equity ratios for 2024 and frequency of future adjustments
Questions

1. Are there changes in the business, regulatory and financial risks of the Alberta utilities since the 2018 generic cost of capital proceeding that warrant a change in the deemed equity ratios presently approved by the Commission?

No. Please refer to the evidence of Mr. Bell.

(a) Do the three primary quantitative credit metric targets relied on by the Commission continue to support an A-range credit rating?

Yes. Please refer to the evidence of Mr. Bell.

2. Should the Commission update deemed equity ratios during the period a formulaic approach to determine ROE is in operation? If so, why? If not, why not?

No. Please refer to Section 5 of my evidence.

3. Should the Commission determine it appropriate to update deemed equity ratios during the period a formulaic approach is in operation; how often should deemed equity ratios be updated; and what process should be used? Does the Commission's present approach remain appropriate?

As discussed in Section 5 of my evidence, I recommend regular reviews and proceedings every 3-5 years, and never beyond 5 years. A review of equity ratios at such intervals would be appropriate.

Process to review formulaic approach to determine ROE
Questions

1. What process should the Commission use to review whether the formulaic approach that may result from this proceeding produces a fair ROE? How often should this process occur?

As discussed in Section 5, I recommend regular reviews and proceedings every 3-5 years, and never beyond 5 years. I also recommend a review if the A-rated utility yield declines below 3.8%, or if the A-rated yield spread exceeds 2%, which would indicate a period of extreme volatility. In addition, a review would be warranted at any point where extreme market uncertainties and volatility suggest market conditions are extremely abnormal (i.e., similar to levels experienced during the 2008-09 financial crisis for example).

2. If the Commission determines that the formulaic approach does not result in a fair ROE for a given year, what process should the Commission employ to set a fair ROE for that year?

In that case, the Commission should establish new proceedings, such as the current one.

2 THE ECONOMY AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE

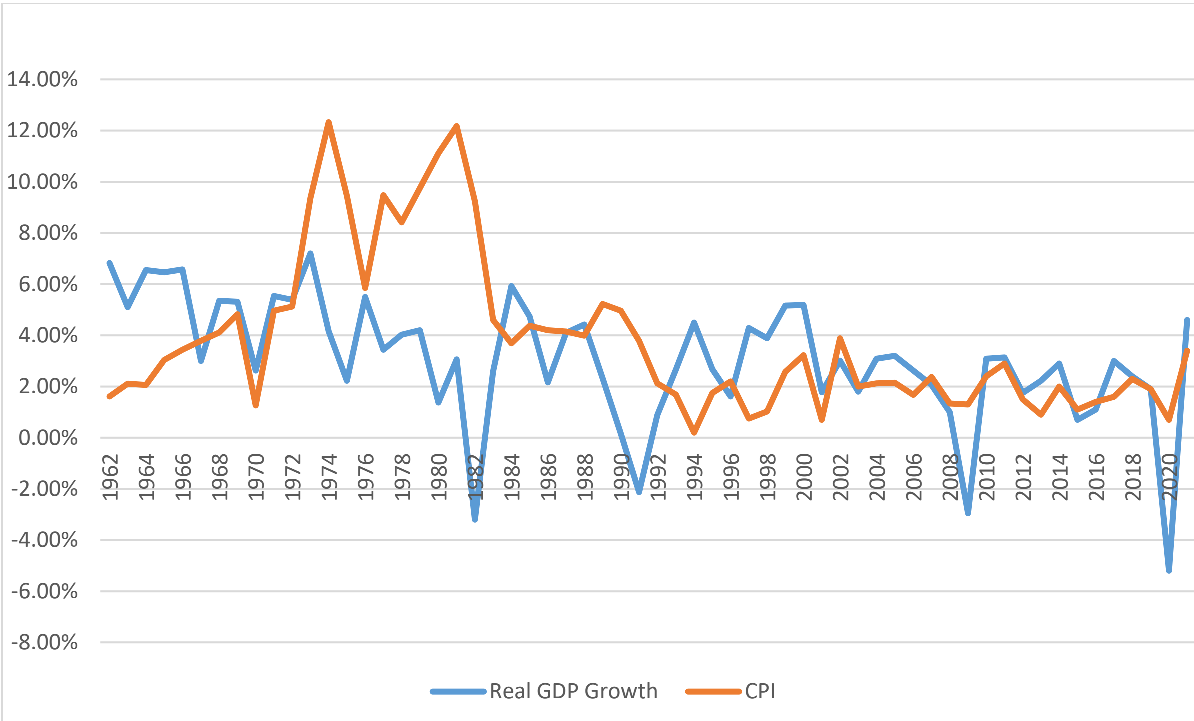
2.1 The Past and Present

2.1.1 GDP Growth and Inflation

Figure 1 below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index ("**CPI**") over the 1962 to 2021 period. The graph shows that real GDP growth has generally been in the 2-6% range, with the exceptions of 2020 (due to COVID) and during three recessionary periods that occurred in the early 1980s, the early 1990s, and during the 2008-09 financial crisis. Table 1 reports summary statistics that show the average GDP growth over the entire period was 3.1% (median 3.0%). It is interesting to note that GDP growth declined to an average of 2.3% (median 2.6%) over the 1992 to 2021 period, which is more in line with forecasts for future growth estimates. This represents the period following the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from Figure 1, and also as measured by the standard deviation of 2.1% for 1992-2021 versus 2.4% for 1962-2021 as reported in Table 1. The working papers for Figure 1 and Table 1, below, are appended as Exhibit A to my evidence.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2021)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2021)

	1962-2021 (%)		1992-2021 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.05	3.79	2.27	1.84
Geometric Average	3.02	3.75	2.25	1.84
Median	3.03	2.74	2.64	1.83
Max	7.20	12.33	5.18	3.88
Min	-5.20	0.20	-2.95	0.20
Std Dev.	2.42	3.04	2.12	0.85

Data Source: Statistics Canada.

The 1962-2021 statistics are obviously driven by the high rates of inflation during the 1970s and 1980s. Up until 2021, inflation rates have generally been within the Bank of Canada's 1% to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average CPI of 1.84% (median 1.83%). CPI growth has also been very stable during this latter period, which is obvious from Figure 1, and also by the huge decline in standard deviation from 3.0% over the entire 1962-2021 period to 0.85% since 1991.

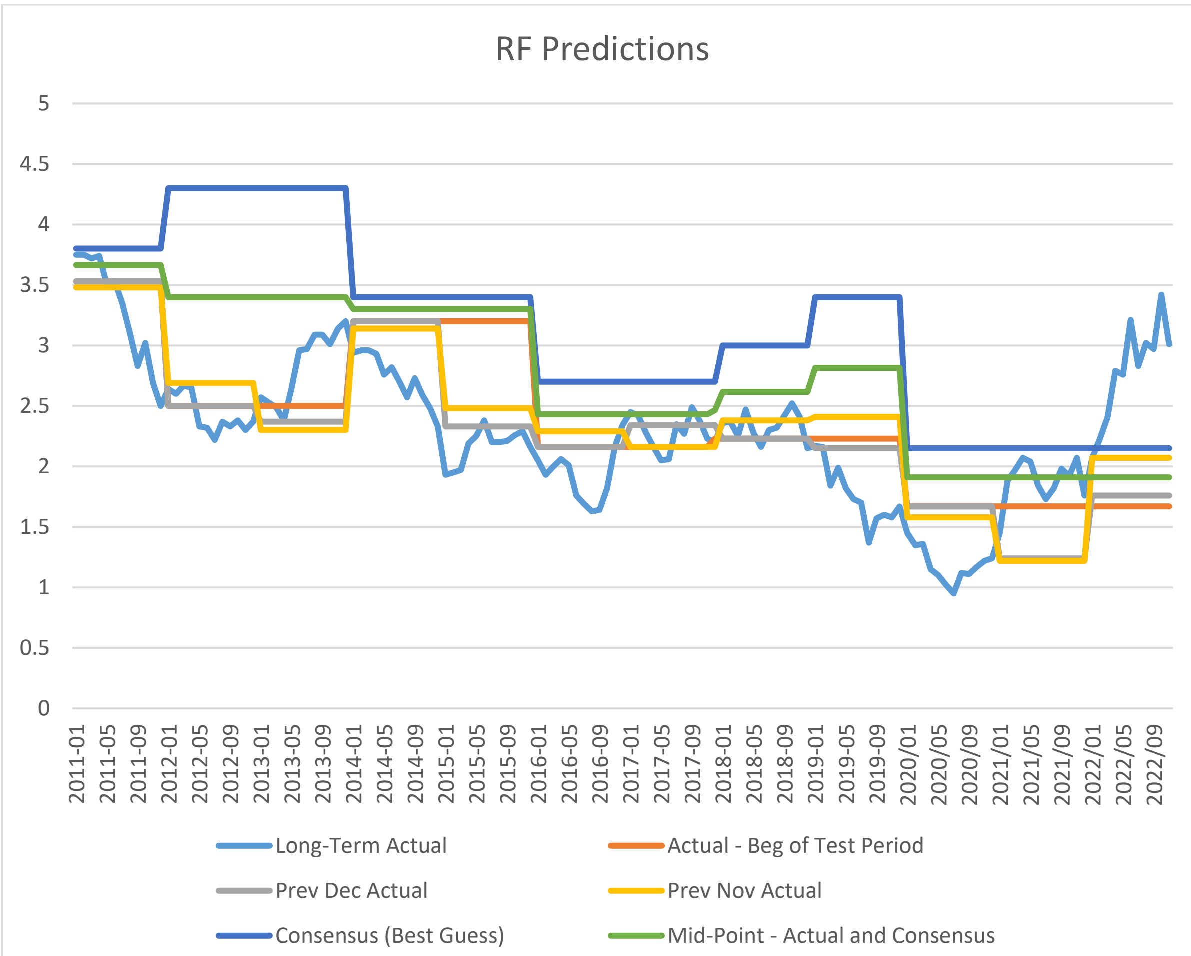
2.1.2 Capital Market Conditions

The 30-year Government of Canada bond yield as of January 19, 2023 was 2.85%, while the 10-year yield was 2.72% - above the rates of 1.67% and 1.61% respectively during December of 2019 that I used when I prepared my evidence in January 2020 for the 2021 GCOC proceedings. During the 2016, 2018 and 2021 GCOC Proceedings, I noted that Consensus forecasts had consistently been too high in previous decisions, and consistent with the approach used by the Commission in its 2013 GCOC Decision (Decision 2191-D01-2015), during those Proceedings I used the actual prevailing long-term yield at the time as a lower bound, and used the Consensus-based estimate as my upper bound. I then used the mid-point of these figures as my base case long-term Canada government bond yield estimate for the subsequent test periods. As argued during previous proceedings, it is beneficial to incorporate existing rates as a base – i.e., as a floor when rates are expected to increase, or as ceilings when rates are expected to decrease, or even as a best estimate, as the Commission did in 2018. In other words, forecasters are often wrong, while existing rates offer the benefit of a starting point that reflects actual yields (i.e., yields that investors can actually achieve today), rather than forecasts which may or may not materialize. In addition to the inaccuracy associated with 10-year yield forecasts, the use of Consensus 10-year yield forecasts is simply the starting point. This is because we must then obtain another "estimate" – i.e., the spread between 10 and 30-year yields, which varies through time, and hence is also subject to estimation errors.

In my evidence below I pick up on the points made above and examine the forecasting ability of Consensus forecasts at the beginning of test periods, versus simply using actual prevailing long-term government yields, as well as the approach of using the mid-point of these two forecasts (as I have done in previous proceedings). I also include forecasts based on using risk-free rate ("**RF**") forecasts based on beginning of calendar year actual long-term government yields (i.e., previous end-of-December yields), and using previous calendar year end-of-November yields. Figure 2 depicts the results of this analysis using data over the 2011-2022 period. Figure 2 demonstrates clearly that the Consensus forecasts were much higher than the actual prevailing rates during the subsequent test periods, whereas the other four forecast approaches performed much better. The working papers for Figure 2 and Table 2, below, are appended as Exhibit B to my evidence.

FIGURE 2

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2011-January 2023)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

In order to examine the accuracy of the forecasts, I include Table 2 which provides summary statistics that confirm the superior RF forecasting ability of simply using the actual prevailing long-term government yields versus using Consensus forecasts. In particular, the average difference between subsequent actual long-term government yields and forecasts (i.e., the forecast error) using Consensus forecasts at the beginning of the respective test period over the

January 2011-January 2023 period is 0.8295%, which is more than eight times the average error of 0.1012% using the beginning of test period actual prevailing long-term government yield. Further, the estimates are *greater* than the actual prevailing rates 93.0% of the time, versus 56.6% of the time for using the actual yields – so the Consensus estimates have consistently been ***upward biased***. In other words, using Consensus forecasts would have added an average excess allowed ROE of 0.83% (borne by the consumer), at least in terms of CAPM forecasts, whereas using actual prevailing RF rates would have added on average only 0.10% relative to actual prevailing RF rates. Relatedly, Table 2 shows that the mean squared error (MSE) of the Consensus forecasts is 1.1571 versus 0.3238 when using actual RF at the beginning of the test period, and this difference is statistically significant. In other words, using beginning of test period actual long-term government rates as a forecast for future RF values would provide statistically significantly better forecasts of these rates. The last column in Table 2 includes RF forecasts made using the mid-point of prevailing RF rates and Consensus forecasts, an approach that both myself and the Commission have used in previous proceedings. Table 2 shows that while this approach is significantly better than using Consensus forecasts, with an average error of 0.4651% and an MSE of 0.5339, it clearly underperforms forecasts that simply use the actual RF at the beginning of the test period. I will revisit this evidence later when I discuss my RF estimate for the CAPM.

TABLE 2

STATISTICS FOR LONG-TERM CANADA BOND YIELD FORECASTS

(2011-January 2023)

	Difference Actual at Beginning of Test Period	**Difference using previous December Actual**	**Difference using previous November Actual**	**Difference using Consensus Forecast at Beginning of Test Period**	**Difference using Mid-Point at Begin of Test Period**
Average	**0.1012**	**-0.0044**	**0.0538**	**0.8295**	**0.4651**
Median	0.11	0.08	0.13	0.80	0.46
Max	1.27	1.03	1.04	2.08	1.44
Min	-1.75	-1.66	-1.35	-1.27	-1.51
StdDev	0.5620	0.5059	0.4967	0.6872	0.5655
Mean Squared Error (MSE)	**0.3238**	**0.2541**	**0.2479**	**1.1571**	**0.5339**

Data Source: Statistics Canada.

Table 2 also includes RF forecasts using beginning of calendar year actual long-term government yields (i.e., previous end-of-December yields), and forecasts using the previous calendar year November yields. As one would expect, such RF forecasts are not only much better than Consensus forecasts and mid-point forecasts, they also are better than those made using beginning of test period actual RF rates. This is because the actual rates used for forecasting purposes are more “timely.” Table 2 shows that using December yields provides an average forecast error of -0.0044% (i.e., virtually zero) with an MSE of 0.2541, while using previous November yields provides a similarly small average forecast error of 0.0538% and an MSE of 0.2479. Both of these estimators provide statistically significantly superior estimates to both Consensus forecasts and mid-point forecasts. I will revisit this evidence later when I discuss my recommended AAM for allowed ROEs.

The fact that using existing rates would have worked much, much better than using Consensus forecasts over the January 2011-January 2023 period is well-supported by academic studies.

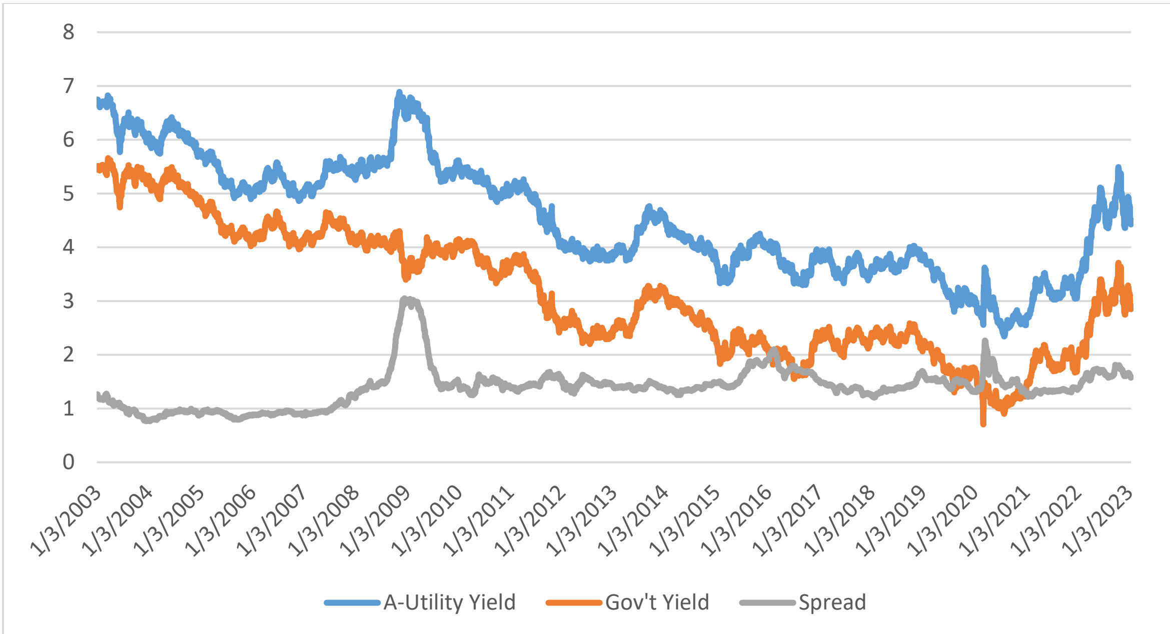
For example, a study by Hafer and Hein (1989)[2] shows that economic forecasters do not perform any better than using futures rates, and perform **worse** than naïve forecasts (i.e., simply using the existing rates). In particular, this study shows that naïve forecasts perform the best under one of their measures of accuracy, while using interest rate futures performs best under their other measure of forecasting accuracy. Economic forecasters, on the other hand, perform worst under both measures of forecast accuracy. Similarly, a 2005 study by Mitchel and Pearce (2007)[3] examined the six-month-ahead forecasts of Treasury bill and Treasury bond rates from 1982 to 2002. This study found that: "Most economists' forecast accuracy is statistically indistinguishable from a random walk model in forecasting the Treasury bill rate, but many are significantly worse in forecasting the Treasury bond rate and the exchange rate."[4] Yet another study by Spiwoks, Bedke and Hein (2008)[5] examined 10-year US government bond yield and three-month US Treasury bill rate forecast accuracy for the 1989 to 2004 period. They found that "sign accuracy is significantly better than random walk forecasts in only a very few of the forecast time series." This indicates forecasters are not very successful in simply forecasting the direction of future interest rates. Not surprisingly, they further find that "the information content of most of the forecast time series is lower than that of the naïve forecasts."

The total cost of borrowing to utilities is a function of both the level of government yields and the yield spreads on utility bonds, as I have noted in my previous evidence. Figure 3 shows that since the time I prepared evidence in January of 2020, both long-term government yields and A-rated utility yields have increased. In particular, as of January 19, 2023 the A-rated utility yield was 4.43%, versus 3.02% as of January 13, 2020, an increase of 1.41%. Given the 30-year Government of Canada yield of 2.85% as of January 19, 2023, this implies an A-rated utility yield spread of 1.58% versus the spread of 1.31% as of January 2020, and the average spread of 1.39% over the 2003-January 19, 2023 period. The working papers for Figure 3 are appended as Exhibit C to my evidence.

[2] This article is appended to my evidence as Exhibit AA.
[3] This article is appended to my evidence as Exhibit AB.
[4] The random walk model is equivalent to using naïve forecasts, as defined above.
[5] This article is appended to my evidence as Exhibit AC.

FIGURE 3

A-UTILITY YIELDS (January 1, 2003-January 19, 2023)

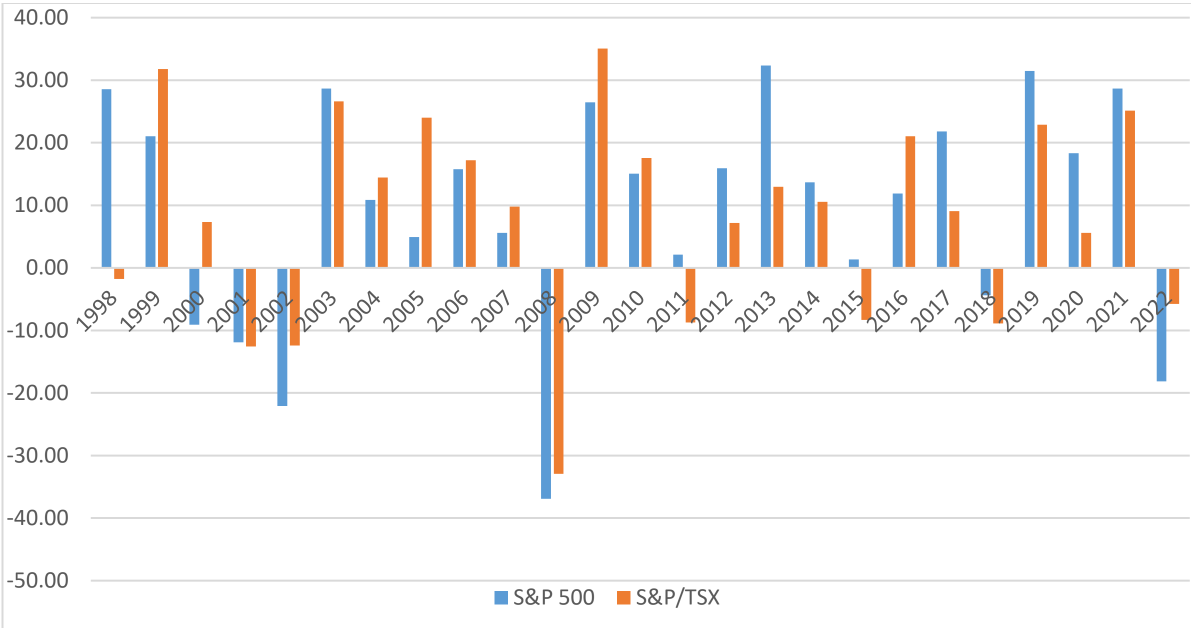


Source: Bloomberg.

Following a year of strong performance during 2021 with a total return of 25.2%, the Canadian stock market had a tough year during 2022, with a loss of 5.8%. U.S. markets did better than Canada in 2021 with a return of 28.7%, but did much worse during 2022, producing a loss of 18.1%. Figure 4 provides the average annual total stock returns for Canada and the U.S. over the 1998-2022 period. Over this period, stocks in Canada provided an average return of 8.3% (geometric mean of 7.0%), while U.S. stocks provided an average return of 9.3% (geometric mean of 7.6%). These figures are consistent with long-term “real” stock returns in the 6% to 7% range, and current market return expectations (both of which are discussed in Section 3.2.3). The working papers for Figure 4 have been appended as Exhibit D to my evidence.

FIGURE 4

STOCK MARKET RETURNS (%) - (1998-2022)



Source: Bloomberg

The trailing price-earnings ("**P/E**") ratio for the S&P/TSX Composite Index stood at 12.8 on December 21, 2022, while the P/E ratio for the U.S. S&P 500 Index was 18.6 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below 15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 13 to 19 range in Canada and the U.S. are in familiar territory; albeit slightly on the low side in the case of Canada, consistent with poor performance during 2022. For example, these figures are in line with the median P/E ratios for the TSX Index (18.9) and the S&P 500 Index (18.7) over the 2012-2022 period. As of the same date, dividend yields were 1.76% in the U.S. and 3.28% in Canada, also within typical ranges; albeit slightly elevated in the case of Canada. For example, the median dividend yields for the TSX Index and the S&P 500 Index over the 2012-2022 period were 2.97% and 1.89% respectively. The working paper supporting these statistics have been appended as Exhibit E to my evidence.

The implied volatility indexes in Canada and the U.S. have averaged in the 16-20 range through time.[6] The Canadian (S&P/TSX 60) and U.S. VIX indices stood at 14.6 and 19.85 respectively as of January 20, 2023. The Canadian VIX indicates below normal volatility, while the U.S. VIX indicates slightly high volatility, but still within traditional ranges.[7] It is important to recognize that these are short-term volatility measures.

Finally, pension fund health is a closely watched and important financial health indicator. Poor stock returns during the 2007-09 crisis, combined with extremely low levels of interest rates, hit the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall Canadian pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 5 depicts the value of this index over the 2008 to Q4-2022 period. The index ended December 2022 at 113%, up 10% from 103% at the start of 2022, and 1% above the level of 112% at which it sat when I prepared my evidence in January 2020. This level is comfortably above 100%, and is well above the all-time low of around 70% in early 2009. Hence, this measure of financial stability indicates stable and solid market conditions, which are nowhere near crisis levels.

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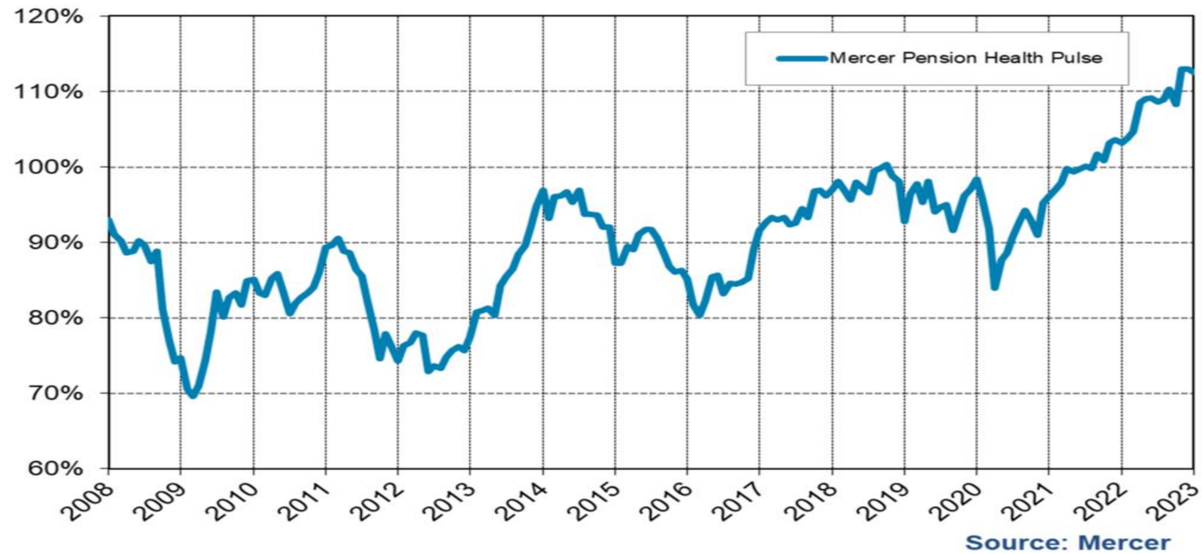
[6] According to Mr. Hevert's 2018 evidence, Exhibit 22570-X0153.01. pages 28-29, the U.S. index had averaged 19.5 since 1990, while the current Canadian index had averaged 16.6 since its inception in 2009.
[7] Sources: https://ca.investing.com/indices/s-p-tsx-60-vix, and https://www.google.com/search?client=firefox-b-d&q=VIX, January 21, 2023.

FIGURE 5

MERCER PENSION HEALTH INDEX - (2008-Q4, 2022)



Source: https://www.mercer.ca/en/newsroom/mercer-pension-health-pulse-q4-2022.html, January 16, 2023.

2.2 The Future

2.2.1 Global Economic Activity

According to the Bank of Canada's January 2023 Monetary Policy Report ("**MPR**"), the global economy is expected to grow slowly during 2023 at 1.9%, with growth expected to pick up to 2.4% during 2024.[8] Table 3 shows that this global growth is expected, despite slower growth in both the U.S. (0.5% and 1.1%) and the Euro zone (0.2% and 0.9%) during 2023 and 2024. Meanwhile, Chinese GDP growth is expected at 5.4% during 2023 and at 5.0% during 2024.

[8] This report is appended to my evidence as Exhibit AD.

TABLE 3

REAL GDP GROWTH GLOBAL FORECASTS (2023-2024)

	Real GDP Growth (%)	
	2023	**2024**
World	1.9	2.4
U.S.	0.5	1.1
Euro Zone	0.2	0.9
China	5.4	5.0

Source: Bank of Canada MPR (January 2023).

The Bank of Canada discusses several factors affecting global economic growth in its January 2023 MPR. The Bank suggests that global inflation has peaked and is declining in several countries, but is not showing “sustained improvement” in many advanced economies, where labour markets remained tight while consumer spending remained robust. While many central banks were near the end of tightening cycles, some were still expected to tighten further. In addition, Russia’s invasion of Ukraine continued to impact global commodity markets and the European economies. However, despite these monetary conditions and geopolitical uncertainties, global economic activity was stronger than expected.

2.2.2 Canada’s Outlook

The Bank of Canada notes in its January 2023 MPR that Canadian economic growth had been solid at 5.0% during 2021, and at an estimated 3.6% during 2022. The Bank noted that inflation had declined from its peak, but was still too high; although lower energy prices, reduced supply chain issues, and higher interest rates were beginning to reduce inflationary pressures. As a result, they expect inflation “to fall to 3% by mid-2023 and return to the 2% target in 2024.” The Bank expects slow economic growth for the last part of 2022, which will continue through the first half of 2023, as tighter monetary policy continues to impact the housing market, and expand to exert greater pressure on consumer spending on durables and beyond, and on business investment. The Bank expects growth to rebound during the second half of 2023.

Overall, Table 4 shows that the Bank forecast slow real GDP growth of 1.0% for 2023, before rebounding to a modest 1.8% for 2024.

Table 4 also includes real GDP forecasts from CIBC World Markets, BMO Capital Markets, Desjardins, Economic Intelligence Unit, Oxford Economics, TD Bank, Scotiabank, OECD, and the IMF.[9] The average of the 2022 Real GDP forecasts of 3.32% is slightly below that from the Bank of Canada (3.6%), while the 2023 average forecast of 0.97% is the same as the Bank's forecast of 1.0%.

TABLE 4

REAL GDP GROWTH FORECASTS – CANADA (2022-2024)

	2022	2023	2024
CIBC World Markets	3.1	0.6	
BMO Capital Markets	3.5	3.0	
Desjardins	3.6	0.2	
Econ Intell Unit	3.2	2.0	
Oxford Economics	2.9	-1.1	
TD Bank	3.5	0.7	
Scotiabank	3.6	0.8	
OECD	3.2	1.0	1.3
IMF	3.3	1.5	
Average	**3.32**	**0.97**	
Max	3.6	3.0	
Min	2.9	-1.1	
Bank of Canada	**3.6**	**1.0**	**1.8**

Source: Exhibits AE through AM, and Bank of Canada MPR (January 2023).

Based on the discussion above, the Bank predicts that inflation will remain above its target range during 2023 at 3.6%, before declining to 2.3% just above the mid-point of its target range during 2024. Table 5 shows that the Bank's 2023 inflation projection is identical to the average of the other forecasts of 3.6%.

[9] These reports supporting the figures provided in Tables 4, 5 and some of the figures in Table 6 are appended to my evidence as Exhibits AE through AM.

TABLE 5

CPI FORECASTS – CANADA (2022-2024)

	2022	2023	2024
CIBC World Markets	6.9	3.2	
BMO Capital Markets	5.5	3.5	
Desjardins	6.9	3.2	
Econ Intell Unit	NA	NA	
Oxford Economics	5.5	2.7	
TD Bank	5.6	3.8	
Scotiabank	6.8	4.1	
OECD	6.8	4.1	2.4
IMF	6.9	4.2	
Average	**6.36**	**3.6**	
Max	6.9	4.2	
Min	5.5	2.7	
Bank of Canada	6.8	3.6	2.3

Source: Exhibits AE through AM, and Bank of Canada MPR (January 2023).

Of course, there are always uncertainties associated with economic projections. The Bank noted that the main upside risk to their inflation outlook is that consumer price inflation remains stickier than expected as a result of unanticipated labour cost pressures and a resurgence in global energy prices. The key downside risk to their inflation forecast would be a severe global economic downturn; although they note the chances of this occurring have declined since the time it released its October MPR.

2.3 Capital Market Conditions and Expectations

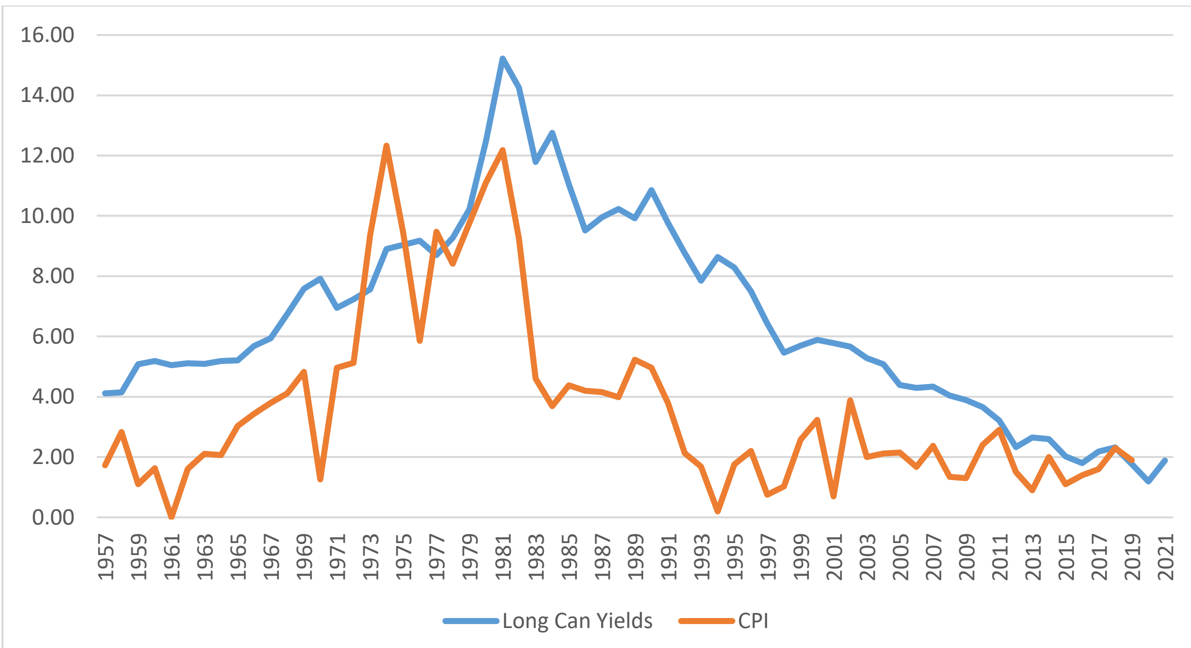
2.3.1 Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 6 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation, with a correlation coefficient of 0.67 over the 1957-2021 period. Of course, yields are determined based on “expected” inflation, and we can see a few years in the 1970s where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since

1991 is obvious from the graph, with inflation hovering around the 2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 3.64%, with inflation averaging 1.94%. Not only have long-term Canada bond yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005, or 4% since 2008.

FIGURE 6

BOND YIELDS AND INFLATION – CANADA (1957-2021)

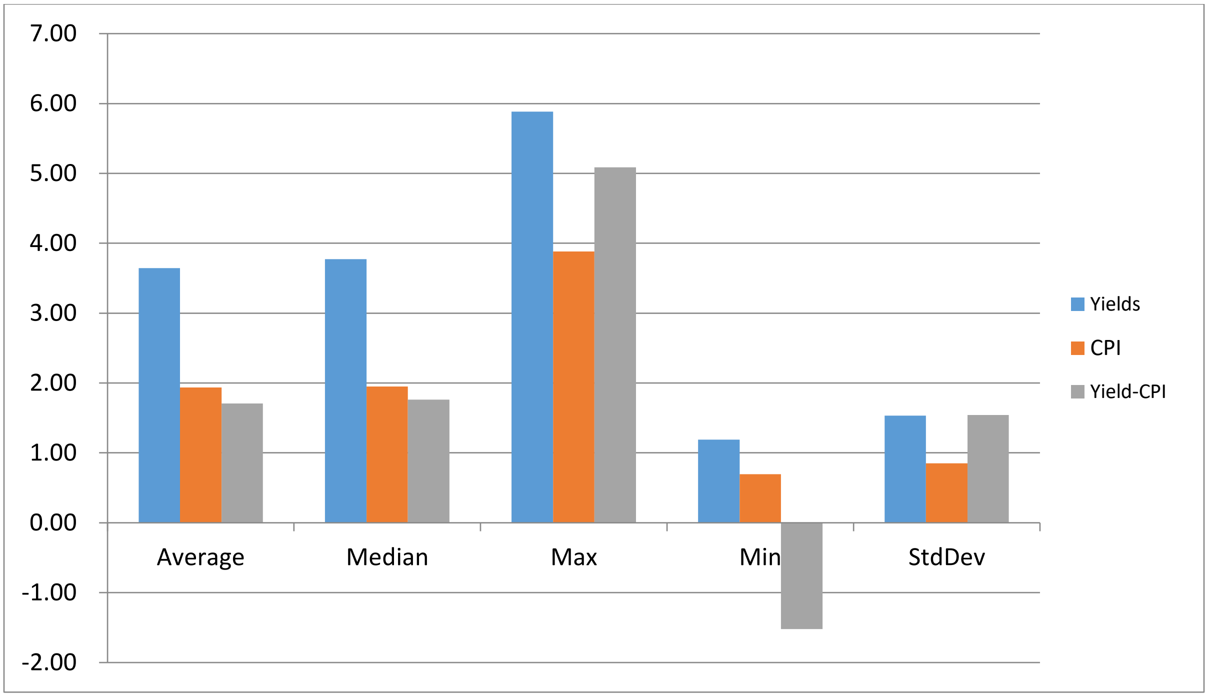


Data Source: CANSIM database.

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 6. This can also be seen in the standard deviations reported in Figure 7, which reports summary statistics for the 1998 to 2021 period. For example, the standard deviation of the yields was 1.53% over this period, versus 3.25% over 1957-2021. Figure 7 also shows that the difference between yields and inflation averaged 1.71% over the 1998-2021 period, with a standard deviation of 1.54%. The working papers for Figure 6 and Figure 7 are appended as Exhibit F to my evidence.

FIGURE 7

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2021)

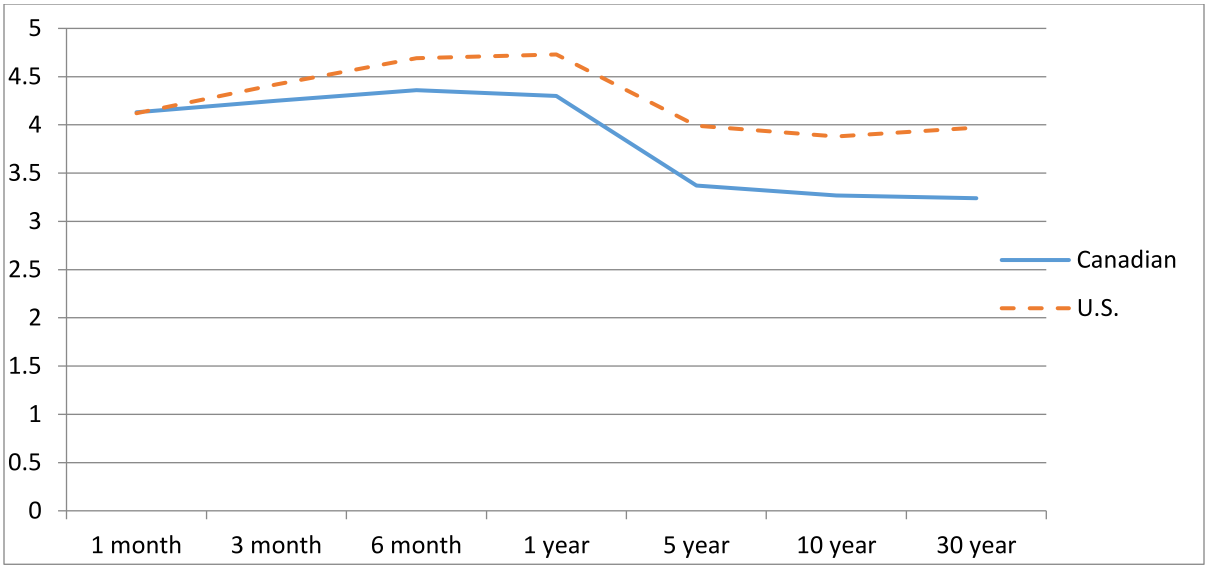


Data Source: CANSIM database.

Figure 8 below depicts the yield curves for Canada and the U.S. as of the end of December 2022. We can see that one-month rates are the same in both countries, but beyond that the short-term U.S. rates were 0.20-0.40% above Canadian rates up to one year. The longer term U.S. rates were considerably higher, in the range of 0.60-0.70% for 5-, 10-, and 30-year yields. The working papers for Figure 8 are appended as Exhibit G to my evidence.

FIGURE 8

YIELD CURVES – CANADA AND THE U.S. (DECEMBER 2022)



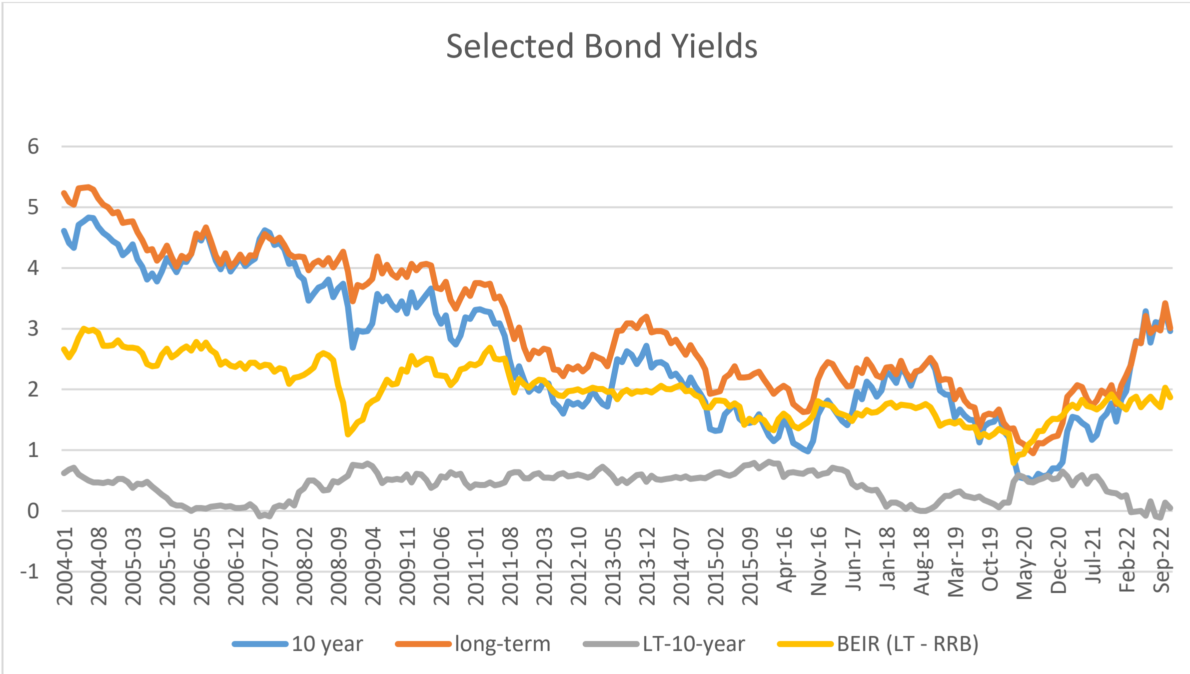
Sources: U.S. Data - https://home.treasury.gov/policy-issues/financing-the-government/interest-rate-statistics?data=yield, December 30, 2022. Canadian data – https://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/, December 28, 2022.

2.3.2 Interest Rate Levels

Figure 9 shows 10-year and long-term bond yields in Canada over the last 19 years, which have moved in tandem for the most part, with a correlation coefficient of 0.98 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.42% (0.48%) over the entire period. It is obvious from Figure 9 that this spread has narrowed considerably during the 2018-22 period, averaging 0.26% over these five years, and sitting at 0.05% at the end of November 2022, with long-term rates of 3.01% and 10-year rates of 2.96%. Figure 9 also shows the break-even inflation rate ("**BEIR**"), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR is often viewed as an indicator of future inflation rates. This rate remained within the Bank of Canada's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.22% in August 2019, and averaging 1.98% overall, right at the Bank's target rate. It sat at 1.87% at the end of November 2022, well below both the Bank's 2022 CPI forecast of 4.1% and the average forecast of 3.6% from Table 4, and also below the Bank's 2024 forecast of 2.2%. The working papers for Figure 9 are appended as Exhibit H to my evidence.

FIGURE 9

SELECTED BOND YIELDS – CANADA (January 2004-November 2022)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Table 6 includes the forecasts for Government of Canada 10-year bond yields for the nine organizations included in the GDP and CPI forecasts included in Tables 4 and 5. Forecasts were not available for all nine organizations, but the average of the provided forecasts were 3.06% as of March 2023 and 2.99% as of December 2023. These forecasts were made during Q3 and Q4 of 2022, 10-year yields were around or above 3%, 30 basis points or more above the yield of 2.72% as of January 19, 2023.

Despite the consistent inaccuracy of yield forecasts, if we assume the predicted increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 3.03 – an increase of 0.18% from existing yields. Using the January 19, 2023 spread between 10-year and long-term bond yield spreads of 0.13% we would get a 2023 forecast for long-term government yields of 3.16%, and using the 2018-22 average spread between the two rates of 26 bp, we would obtain forecasts of 3.29%. If we used the long-term average 42 bp spread of 30-year yields over 10-year yields, we would obtain an estimate of 3.45%; although this would require a significant widening from the current 10-year and long-term yield spreads of 0.13%.

Considering the mid-point of the current spread of 0.13% and the most recent five-year average of 0.26%, we could add 0.20% to the average 10-year yield forecast of 3.03% to get a forecast of 3.23%. However, as discussed in Section 2.1.2, there is compelling evidence provided in Figure 2 and Table 2 that supports simply using the actual yields at a given point in time to predict future yields, and this is the approach I will employ in estimating future yields.

TABLE 6

10-YEAR YIELD FORECASTS – CANADA

	March 2023	December 2023
CIBC World Markets	3.35	3.20
BMO Capital Markets	NA	NA
Desjardins	2.70	2.60
Econ Intell Unit	NA	NA
Oxford Economics	NA	NA
TD Bank	2.80	2.80
Scotiabank	3.40	3.35
OECD	NA	NA
IMF	NA	4.0
Average	**3.06**	**2.99**
Max	3.40	3.35
Min	2.70	2.60

Source: Exhibits AG, AN through AQ.

2.3.3 Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 7 reports summary statistics for Canadian capital markets over the 1938 to 2022 period. The working papers for Table 7 are appended as Exhibit I to my evidence.

TABLE 7

CAPITAL MARKET SUMMARY STATISTICS – (1938-2022)

1938-2022 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (in CAD)
Average	3.66	10.96	5.98	4.45	12.73
Median	2.73	11.02	4.03	3.59	13.43
Std. Dev.	3.33	16.26	9.51	4.18	17.11
Geo. Mean	3.60	9.73	5.57	4.37	11.46

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM. The 2022 CPI figure is the 2022 CPI estimate provided by the Bank of Canada in its October 2022 MPR.

The long-term average return in the Canadian stock market over this period was 10.96%, with a geometric mean of 9.7%. This occurred over a period in which inflation averaged 3.7% (geometric mean of 3.6%) and real GDP growth was higher than it has been recently. This implies "real" returns of approximately 7.3% (6.1%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.1% to 9.3% going forward. These numbers are higher than the average and also most current estimates of expected stock returns going forward by market professionals, as will be shown in Table 8 and as discussed in Section 3.2.3.

2.4 The Alberta Economy

The Conference Board of Canada ("**CB**") December 2022 Provincial Outlook, appended as Exhibit AR to my evidence, estimated that the continuing war in Ukraine and resulting strength in the resource sector would result in strong growth for Alberta during 2022, resulting in a real GDP growth rate of 4.7%. They also forecast this growth would carry over into 2023 with expected GDP growth of 2.8%, driven by recovery in the oil and gas sector during the second half of 2022, and strength in employment figures. The CB went on to forecast continued strong growth rates for the Alberta economy during 2024 and 2025 of 2.7% and 2.2% respectively.

3 ROE CALCULATIONS

3.1 Some Notes on Allowed ROEs

In the 2018 GCOC Proceeding, I noted that allowed ROEs have not declined adequately in response to the reduction in the cost of capital that utilities' have experienced, as long-term government bond yields (or RF) and A-rated utility bond yields have declined significantly over the last two decades. Figure 10 shows that since 2004, both RF and A-rated utility yields have declined markedly, while the allowed ROEs have declined much less so over this period. As a result, the spreads between allowed ROEs and these measures, both of which directly affect the utilities' cost of capital, have *increased* dramatically though the years. Figure 11 depicts these ROE-RF and ROE-A yield "spreads," both of which have increased dramatically throughout this period.[10] For example, in January 2004, the allowed ROE for Alberta utilities was 9.6%, at a time when 30-year government yields (RF) were 5.3% and A-rated utility yields were 6.1%. So, the spreads between the ROE and RF was **4.3%**, and between ROE and A yields was **3.5%**. As of January 19, 2023, the allowed ROE was 1.1% lower than in 2004 at 8.5%, while RF was 2.45% lower at 2.85%, and A yields were 1.67% lower at 4.43%. As a result the ROE-RF spread was 1.35% higher at **5.65%** (a 31% increase), while the ROE-A yield spread was 0.57% higher at **4.07%** (a 16% increase). The average ROE-RF spread during the January 2004-January 2023 period was 5.65% and the average ROE-A-yield spread was 4.24%. Unfortunately, the fact that allowed ROEs have not decreased proportionately to changing capital market conditions and the associated reduction in the costs of capital to utilities has resulted in awarded ROEs that have been well in excess of their cost of equity, with the costs being borne by consumers.

[10] The working papers for Figures 10 and 11 are appended as Exhibit J to my evidence.

FIGURE 10

ALLOWED ROES, GOVERNMENT YIELDS

AND A-RATED UTILITY YIELDS (January 2004-January 2023)

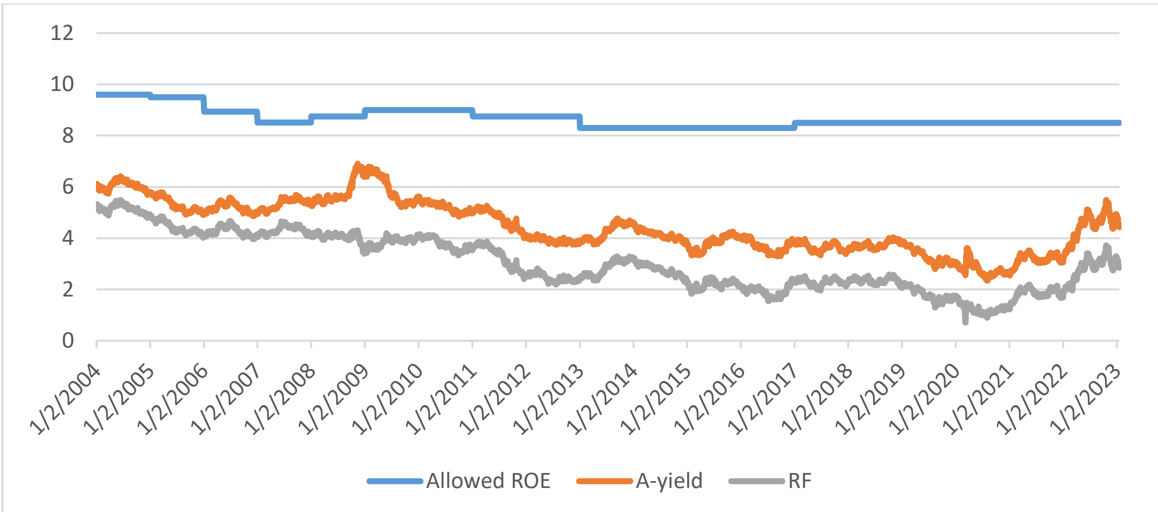
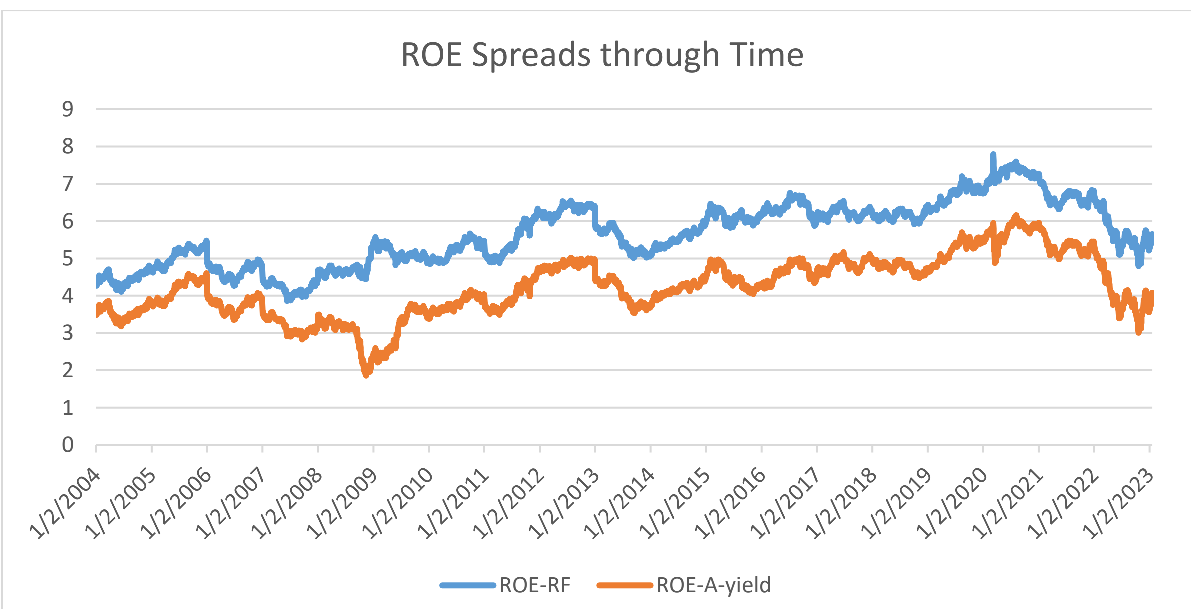


FIGURE 11

ALLOWED ROE-RF and ROE-A-YIELD SPREADS

(January 2004-January 2023)



The downward "stickiness" in awarded ROEs noted above is not unique to Alberta but can be observed in other Canadian jurisdictions, and is even more prevalent in the U.S., which is evidenced in the results of a 2017 study that examines "a dozen years' of gas and electric rate-setting decisions" in the U.S. and Canada over the 2005-2016 period.[11] This study provides evidence "demonstrating empirically that allowed returns on equity diverge significantly and systematically from the predictions of accepted asset pricing methodologies in finance." A large part of this can be explained by the fact that allowed ROEs "tend to exhibit considerable stickiness around focal 'odometer' points." Consistent with the evidence for Alberta discussed above, the authors note that "awarded ROE spreads over risk free treasuries have progressively *widened* significantly since 2005, even though systematic risk in the utilities industry has *fallen continuously* during the same time period." As a result, the authors find that:

> Indeed, if the awarded ROEs were an asset class, they would generate a mean positive abnormal return ("alpha") of between 7.5 and 8.5 percent, an amount that overshadows even the performance of Fortune Magazine's top twenty stock investments for the last decade.

A recent study by Sikes (2022) entitled "Regulatory Inequity" shows that the average awarded ROE is much greater than the average utility's cost of equity, which means that any investments undertaken by the utilities creates value (i.e., generates economic rent).[12] He examines the FERC's Opinion 569-A, issued in May 2020 as a case study to examine the appropriateness of allowed ROEs at a broader level, since the decision and the decision process are typical of most rate decisions, noting (on page 4) that:

> It is in fact an apt case-study which encompasses the prevailing methodologies used, in one form or another, by utility commissions throughout the nation to determine the ROE. As such, examination of the fallacies behind Opinion 569 reveals in general how regulators' acceptance of flawed financial analysis inflates the profit of public utilities.

Sikes notes flaws in the implementation of Risk Premium methodologies and DCF analysis, which lead to upwardly biased estimates. He suggests that the CAPM is the only viable approach, but goes on to note that typical CAPM estimates are also upwardly biased due to

---

[11] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2994314). Appended to this evidence as Exhibit AS.

[12] Source: Sikes, Thomas, M. S. January 2022, "Regulated Inequity – How regulators' acceptance of flawed financial analysis inflates the profit of public utility companies in the United States". Appended to this evidence as Exhibit AT.

typical implementation flaws such as the use of adjusted betas and market risk premiums that greatly exceed current expectations of market professionals. He goes on to conclude (page 71) that "Generations of utility regulators and financial analysts have become inculcated in the idea, at least implicitly, that utilities are fairly compensated with an ROE similar to that expected from the average firm. Because of this, there will be inertia in moving towards the truly just and reasonable ROE."

3.2 Capital Asset Pricing Model Estimates

3.2.1 CAPM Overview

This section employs the commonly used CAPM to estimate the allowed ROE for the average regulated Alberta utility. Essentially CAPM can be used to estimate the required ROE (or Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

Ke = RF + (ERm – RF) Beta

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of financial analysts;[13]
- by over 70 percent of U.S. CFOs;[14]

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[13] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AU.

[14] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AV.

- by close to 40 percent of Canadian CFOs.[15]

Of course, the CFOs and analysts are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous decisions, which is appropriate in my opinion, and as recommended by Sikes (2022).

A recent study by Berk and van Binsbergen (2017)[16] also provides support for the use of CAPM as the most widely used model by investors, stating:

> We find that investors adjust for risk by using the beta of the capital asset pricing model (CAPM). Extensions to the CAPM perform poorly, implying that investors do not use these models to compute discount rates.[17]

The authors go on further to highlight the fact that this model should be used by practitioners, despite its limitations, quite simply because it is the most widely used model by investors, who in turn drive equity returns:

> We have demonstrated that among a range of proposed models, the CAPM—though perhaps far from being a perfect model of risk—is most consistent with investor behavior. Thus, if the criterion for deciding how to compute the discount rate is to use the method investors use, **practitioners should use the CAPM**.[18]

3.2.2 Estimating RF

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate RF, since it is virtually guaranteed and does not fluctuate. However, it is common practice to use the CAPM to estimate the required return on common equity over many periods, such as when trying to estimate the cost of a firm's common equity financing

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[15] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AW.
[16] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AX.
[17] *Ibid.*, page 25.
[18] *Ibid.*, page 32.

component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are more representative of the rate that could be obtained over longer investment horizons. This practice is consistent with previous decisions.

As discussed in Section 2.3.2, the evidence provided in Section 2.1.2 in Figure 2 and Table 2 supports that using the actual yields at a given point in time to predict future yields performs far superior to both using Consensus forecasts or using the mid-point of actual yields. As a result, I will use the existing long-term government yield of **2.85%** as of January 19, 2023 as my estimate for **RF**.

3.2.3 Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium ("**MRP**"), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 8 below provides useful guidance in determining a reasonable estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into two categories: (1) historical returns; and, (2) current (i.e., 2022) long-term market forecasts from 5 different sources. It is noteworthy that two of the sources of long-term forecasts (i.e., Horizon and Evestment) provide summary statistics based on extensive surveys of finance professionals, and hence Table 8 provides a comprehensive view of the forecasts of the professional finance community. In particular, Horizon's report is based on the forecasts of 40 investment advisors, which includes prominent advisory firms (e.g., Aon, Mercer, and Willis Towers Watson), several large commercial and investment banks (e.g., Bank of New York Melon, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley, UBS, etc.), and large asset managers (e.g., BlackRock, The Vanguard Group, etc.). As such, it provides a comprehensive representation of the views of finance professional managing trillions of dollars of wealth. Similarly, the Evestment report is based upon "over 950 data points from over 30 consultant and/or institutional investor-authored documents."

Sikes (2022) (page 45) verifies the relevance of expected market returns by the financial community, noting "investors' expected market return should effectively set a ceiling on the ROE approved by regulators as utility stock is less risky than the overall stock market." The Commission has also previously noted that such forecasts are informative and reaffirmed this position in the 2018 GCOC Decision, stating:

> Consistent with its determinations in previous GCOC decisions, the Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.[19]

Hence, the Commission believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity is far more relevant than market expectations determined using unrealistic assumptions, such as those provided by the utilities' experts in previous proceedings. In other words, market participant beliefs represent an important and practical "benchmark," against which any utility ROE estimate must be compared. Table 8 provides Canadian, U.S. and global historical evidence and forecasts; however, since I estimate CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence; although I would note that the expected U.S market return is 0.43% below that for Canadian stocks.

TABLE 8

HISTORICAL AND FORECAST EQUITY RETURNS

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
HISTORICAL RETURNS				
1. Historical Data (Cleary Evidence, Table 7, Section 2.3.3)	Historical: 1938-2022	Real: 6.1% GA 7.3% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[20]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl. U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017.[21]	Historical: 1915-2014		Real: 6.5%	

[19] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 97, para. 460.
[20] Appended to this evidence as Exhibit AY.
[21] Appended to this evidence as Exhibit AZ.

Average (Range)		**Real:** **6.5%** (5.6%-7.3%)	**Real:** **7.1%** (6.4%-8.3%)	**Real:** **5.2%** (4.3%-6.0%)
FORECAST RETURNS				
4. Institut québécois de planification financière (IQPF) and Financial Planning Standards Council (FPSC), “Project Assumption Guidelines,” April 2022.[22]	Long-term forecast	Nominal: 6.3%		Nominal: 6.6% (Foreign developed market equities)
5. Horizon Actuarial Services, LLC, 2021 “Survey of Capital Market Assumptions,” 2022.[23]	Intermed. (<10 years) Long-term (10-years or more)		U.S. Large Cap (Nominal) 5.91% (4.0-8.9%) 6.54% (4.6-8.9%)	Non-US Dev. Mkts. 6.54% (4.7-8.2%) 7.08% (5.3-9.3%)
6. Evestment Capital Market Assumptions, June 2020.[24]	Intermed. (10 years or less)		U.S. Large Cap (Nominal): 5.96% (5.00-7.00%)	International Markets (Nominal): 6.59% (6.00-7.00%)
7. Franklin Templeton Investment Solutions, “2023 Global Investment Outlook,” December, 2022.[25]	7-year forecast	Nominal: 7.50%	Nominal: 7.02%	Nominal: International Equities: 8.07%
8. “Capital Market Assumptions: Canadian Dollar, 2022,” BlackRock, November 2022.[26] <u>https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions</u>.	10-year forecast 20-year forecast	Large Cap - Nominal: 8.4% 7.3%	Large Cap – Nominal: 8.8% 8.4%	World excl. Can (in CAD): Nominal: 8.7% 8.2%
Average (Range)		**Nominal:** **7.2%** (6.3%-8.4%)	**Nominal:** **6.77%** (5.91%-8.80%)	**Nominal:** **7.30%** (6.54%-8.70%)

The first three sources in Table 8 provide historical long-term real returns for Canadian, U.S. and global stock returns over three extremely long time periods (i.e., 85 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.5%, with a range of

[22] Appended to this evidence as Exhibit BA.
[23] Appended to this evidence as Exhibit BB.
[24] Appended to this evidence as Exhibit BC.
[25] Appended to this evidence as Exhibit BD.
[26] Appended to this evidence as Exhibit BE.

estimates of 5.6% to 7.3%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.5%, ranging from 7.6% to 9.3%, based solely on historical results.

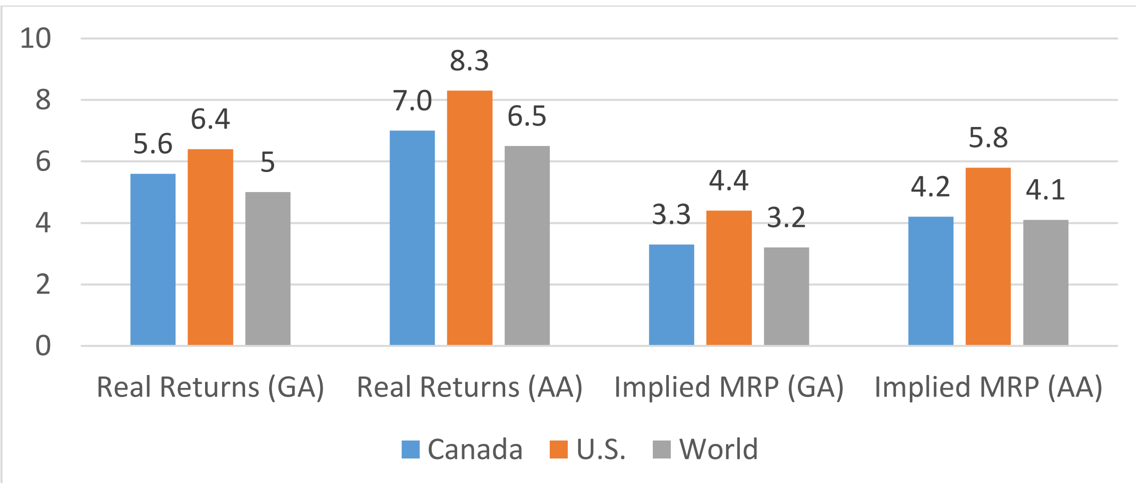
The next five sources represent 2022 estimated long-term market returns from a number of important and reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms, investment and commercial banks, and other investment management firms). All of these estimates are provided in nominal terms. The Canadian market nominal estimates range from 6.3% to 8.4%, and average **7.2%.** Deducting the 2% expected inflation, this translates to an average *real* return of 5.2%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.3% range over the next 5-20 years. While I do not focus on the U.S. evidence, it is noteworthy that the average expected market return for U.S. stocks is 6.77% - 0.43% below that for the Canadian market.

I believe that both historical returns and current expectations of market professionals represent the <u>best</u> sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 8 and discussed above, suggests a range of estimates in the 6.3% to 9.3% range, and an average of 7.2%. I advocate that an appropriate range for expected long-term Canadian stock market returns is 6-9%, and that the mid-point of 7.5% represents an appropriate point estimate. This is slightly above the consensus view of financial professionals of 7.2% that is estimated in the bottom portion of Table 8. It is important to recognize that this expected market return of **7.5%** represents an **upper bound** for the cost of equity to regulated utilities (before adding 0.50% for flotation costs), since they are less risky than the average company in the market. This aligns well with my DCF estimate for the market of 7.46% (in Section 3.2.2), and is below my CAPM estimate for the market of 7.95% (discussed later in this section).

Figure 12 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. figures (5.8% and 4.4%) and slightly below the Canadian figures (4.2% and 3.3%) over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for stock and bond returns over the 1938 to 2022 period, which were 4.98 (4.16%) as previously reported in Table 7. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 13, with 2022 figures of 5.7% and 5.6% respectively.

FIGURE 12

CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)

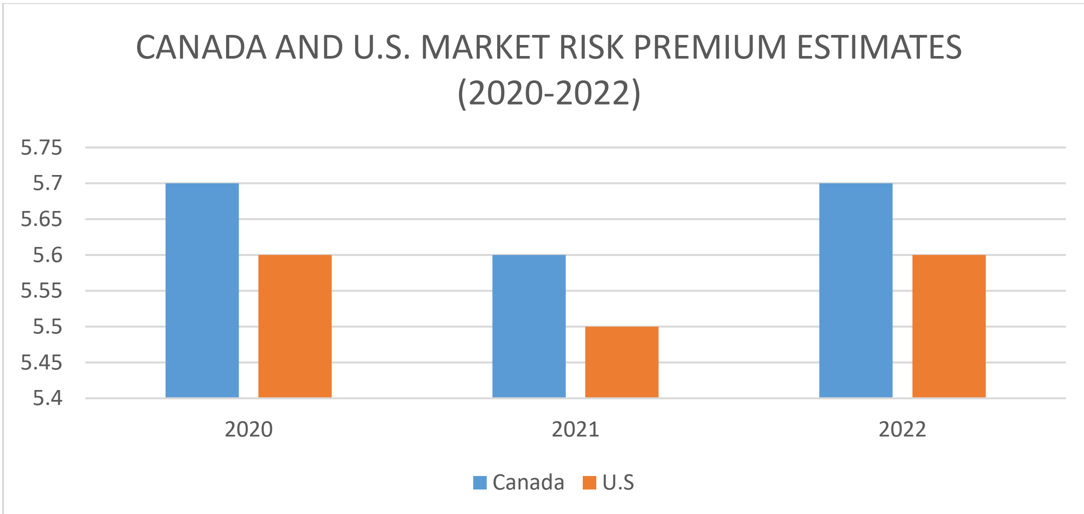


Source: Dimson, E., Marsh, P. and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[27]

[27] Appended as Exhibit AY, noted previously.

FIGURE 13

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2020-2022)



Source: "Survey: Market Risk Premium and Risk-Free Rate Used for 95 Countries in 2022," Pablo Fernandez, Teresa García de Santos, Javier Fernandez Acin. IESE Business School [28]

Based on the previous discussion of capital markets in Section 2.1.2, it appears that stock markets reflect fairly normal conditions in terms of P/E ratios, dividend yields and market volatility as measured by the VIX and Canadian VIX indexes. Therefore, I use an **MRP of 5%**, which is the mid-point of the commonly used 4-6% range. This figure equals the 4.97% average difference between Canadian stock and government bond returns over the 1938-2022 period, is 1.7% above the long-term geometric mean MRP of 3.3%, and is only slightly above the mid-point of 4.95% between the long-term average Canadian MRP of 4.2% and the 5.7% MRP documented by Fernandez et. al (2022). It is also consistent with the practice of using 6% when market uncertainty is well above average, using 5% when markets are close to normal, and using 4% during periods of extreme market and economic optimism. These estimates are also consistent with previous decisions by the AUC. For example, the AUC used an MRP range of 5-7% in the 2013 GCOC Decision[29] and 5.0-7.25% in Decision 2011-474 (the "**2011 GCOC Decision**").[30].

[28] Appended as Exhibit BF.
[29] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 115.
[30] Decision 2011-474, 2011 Generic Cost of Capital, para. 59.

I know from having read numerous investment reports and from having seen numerous presentations from finance professionals that it is common practice to use a range of 3-7% for the MRP when using the CAPM to estimate required returns of equity for firms, with the large majority of MRP estimates falling in the 4-6% range, as noted by Sikes (2022), who cited two market surveys[31], and one research article[32] to support this assertion. In fact, it is so common to use MRPs between 4 and 6%, it is almost assumed. Similarly, it has also always been the case that the MRP would be adjusted upwards during higher periods of uncertainty, and downwards during periods of less uncertainty. I provide some strong evidence below regarding MRPs which is included in two research articles written by prominent finance professors.

In a 2013 working paper, Aswath Damodaran discusses MRP estimation (which he refers to as the equity risk premium (ERP)).[33] In this paper, Dr. Damodaran discusses the results of Merrill Lynch from its monthly surveys of global institutional investors:

> Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update.[34]

This evidence verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, the 3-4.5% range), and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

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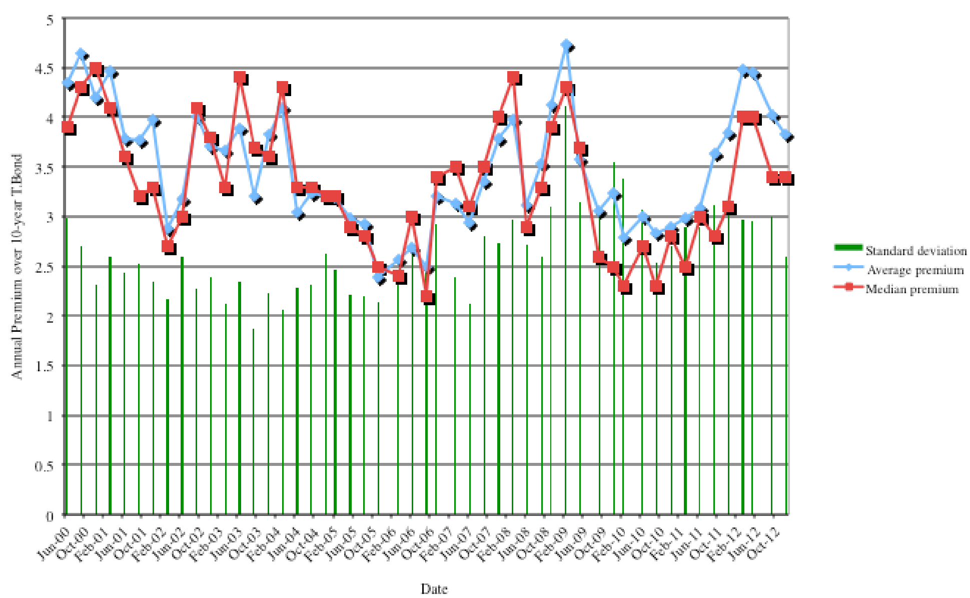
[31] John R. Graham and Campbell R Harvey, "The Equity Risk Premium in 2015" (October 1, 2015). Available at SSRN: https://ssrn.com/abstract=2611793 at 7 (Table 1); and, Pablo Fernandez, Alberto Ortiz Pizzaro, and Isabel Fernandez Acin, "Discount Rate (Risk-Free Rate and Market Risk Premium) Used for 41 Countries in 2015: A Survey" (October 17, 2017). Available at SSRN: https://ssrn.com/abstract=2598104 at 3 (Table 2 – Market Risk Premium) and 4 (Table 3 – Risk Free Rate).

[32] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2021 Edition" (March 23, 2021). Available at SSRN: https://ssrn.com/abstract=3825823, at 91-92.

[33] Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition," Aswath Damodaran, Stern School of Business, New York University. This article is appended as Exhibit BG to this evidence.

[34] *Ibid.,* pages 18-19.

Dr. Damodaran then proceeds to discuss the results of Graham and Harvey (2013)'s surveys of CFOs regarding MRPs:

> To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.
>
> *Figure 2: CFO Survey Premiums*
>
> 
>
>
> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[35]

This evidence also verifies that finance professionals believe that MRPs lie within the 3-6% range (or , more aptly, in the 2.47-4.74% range) over the 2000-2012 period, and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran also discusses the implied MRPs in the S&P 500 Index from 1960-2012 and produces Figure 9, below:[36]

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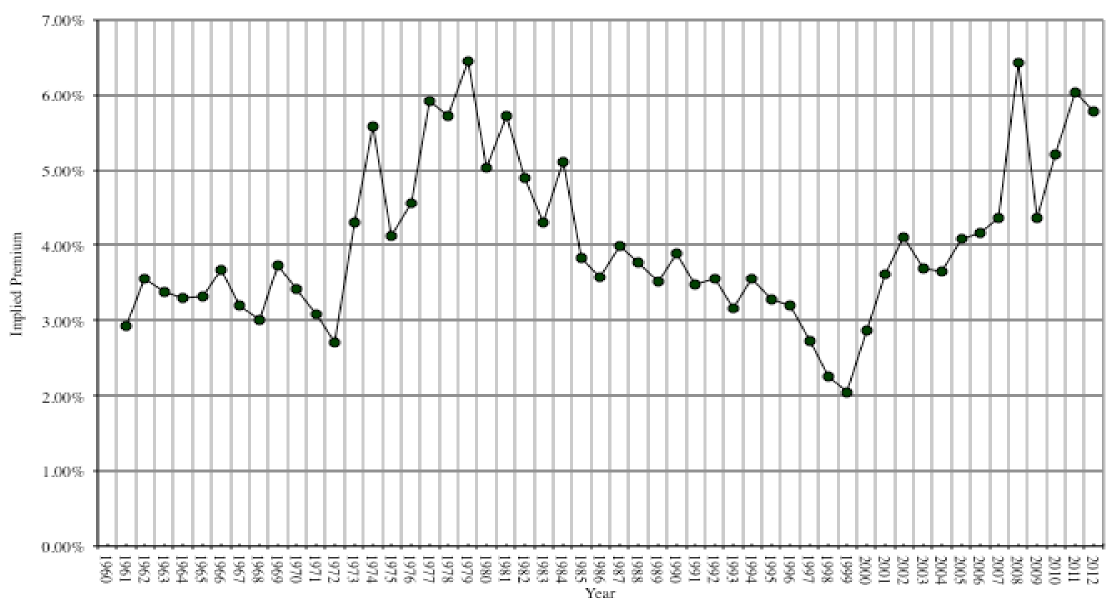
[35] *Ibid.*, pages 20-21.
[36] *Ibid.*, page 74.

Figure 9: Implied Premium for US Equity Market



This evidence also shows that implied MRPs generally lie within the 3-6% range (and in fact are never less than 2% or above 6.5%), and that the MRP increases during periods of uncertainty (e.g., 1979 and 2008), and declines during periods of less uncertainty (e.g., the boom in stock markets at the end of the 1990s).

Dr. Damodaran discusses his own approach to estimating and using MRPs when valuing companies, stating:

> On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5%

> equity risk premium for mature markets in 2010. With the increase in implied premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2013, I will be using a slightly lower equity risk premium (5.80%), reflecting the drop from 2012.[37]

This evidence verifies that a well-respected finance professional, textbook author, and provider of financial data uses MRPs in the 4-6% range and varies his choice of MRP so that it increases during periods of uncertainty, and declines during periods of less uncertainty.

The results of a 2013 survey by Graham and Harvey was discussed above by Dr. Damodaran.[38] I would also note the following conclusions Dr. Graham and Dr. Harvey reached based on their ongoing surveys of CFOs:

> …the CFOs believe that the "risk premium" is a longer-term measure of expected excess returns and best covered by our question on the expected excess return over the next ten years – rather than the one-year question. Three-fourths of the interviewees use a form of the Capital Asset Pricing Model (which is consistent with the evidence in Graham and Harvey, 2001). They use a measure of the risk premium in their implementation of the CAPM.[39]

These conclusions are consistent with the long-term (with adjustments) approach to estimating the MRP that I advocate. It also shows that 3/4ths of CFOs use some version of the CAPM.

Further, Dr. Graham and Dr. Harvey examine the relationship between MRPs and two other common measures of risk aversion that I have referenced previously – the VIX and yield spreads:

> Finally, we consider two measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.52. If the closing day of the survey is used, the correlation is roughly the same.

[37] *Ibid.*, page 79.
[38] "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. This survey is appended to this evidence as Exhibit BH.
[39] *Ibid.*, page 8.

> Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.
>
> We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.54.[40]

This evidence confirms that MRPs tend to increase as risk aversion increases, and decrease as risk aversion declines, which is consistent with my approach to estimating MRPs.

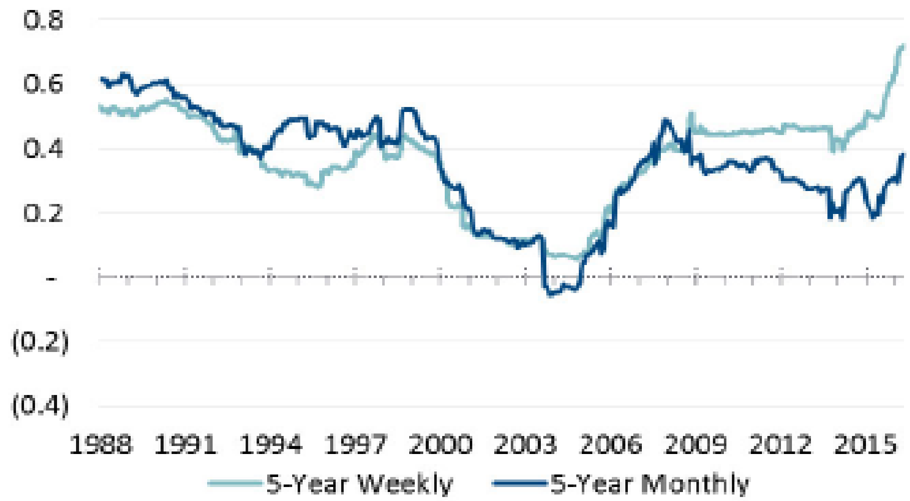
3.2.4 Estimating Beta

We now require a beta estimate to apply the CAPM. I copy below two figures and some of the discussion from Appendix B of my 2018 evidence with regards to historical beta estimates:

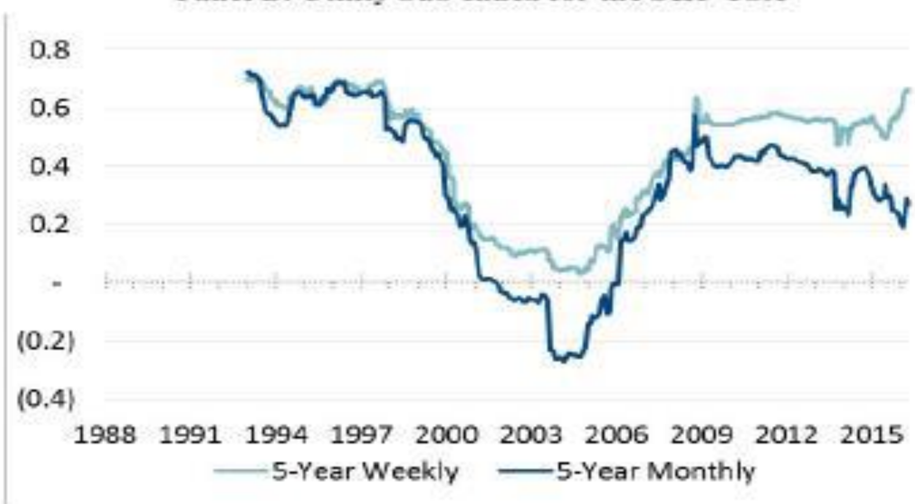
1. I make reference to Figure 6 at page 45 of Dr. Villadsen's rebuttal evidence in the 2016 GCOC proceedings (Exhibit 20622-X0457), which was referenced in VILLADSEN-UCA-16 2017NOV21-014, and is reproduced below. It depicts 5-year rolling monthly and weekly beta estimates calculated (1) over the 1988-April 2016 period for Dr. Booth's sample of Major Canadian Utility Holding Companies (Panel A); and, (2) over the 1992-April 2016 period for the Utility Sub Index for the S&P TSX (Panel B).

[40] *Ibid.*, pages 14-15.

Figure 6: Comparison of Historic 5-Year Monthly and Weekly Betas[136]
Panel A: Simple Average of Booth's Major Canadian Utility Holding Companies



Panel B: Utility Sub Index for the S&P TSX

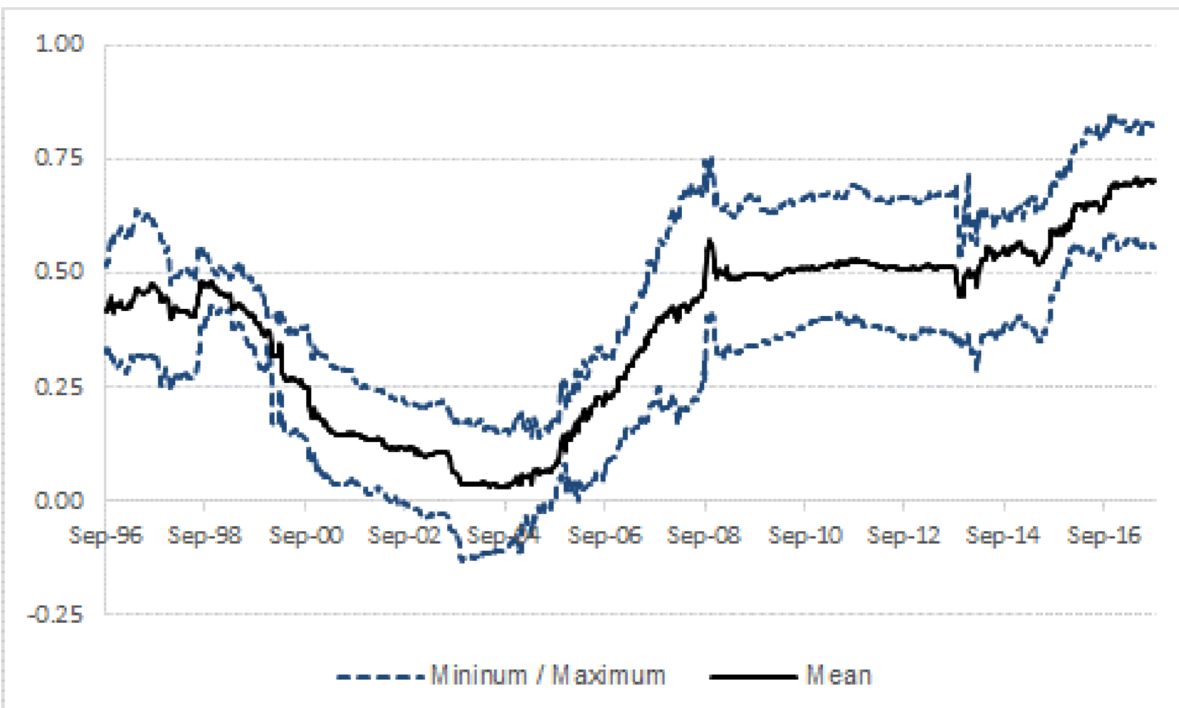


Source: BV Workpaper R06.

The average beta estimate over the 28-year period in Panel A (for Dr. Booth's sample) is **0.35**, while the maximum is 0.63, and the minimum is -0.05. The average beta estimate over the 25-year period in Panel B (for the Utility Sub-Index) is **0.32** for the TSX sample and **0.31** for the Booth sample, while the maximum is 0.72 for the TSX sample and 0.52 for the Booth sample, while the minimums are -0.27 (TSX sample) and -0.05 (Booth sample). The graphs make it very clear that nowhere during this entire period do the beta estimates even come close to 1.0 (i.e., the Booth sample never has a beta estimate exceeding 0.63, while the TSX sample never has a beta estimate exceeding 0.72). This long-term evidence strongly refutes using betas that are adjusted toward one, given long-term average betas in the 0.31-0.35 range, with beta estimates never exceeding 0.63-0.72. Clearly, such an adjustment of beta estimates towards one makes no intuitive sense, since they have never even come close to 1.0 in practice.[41]

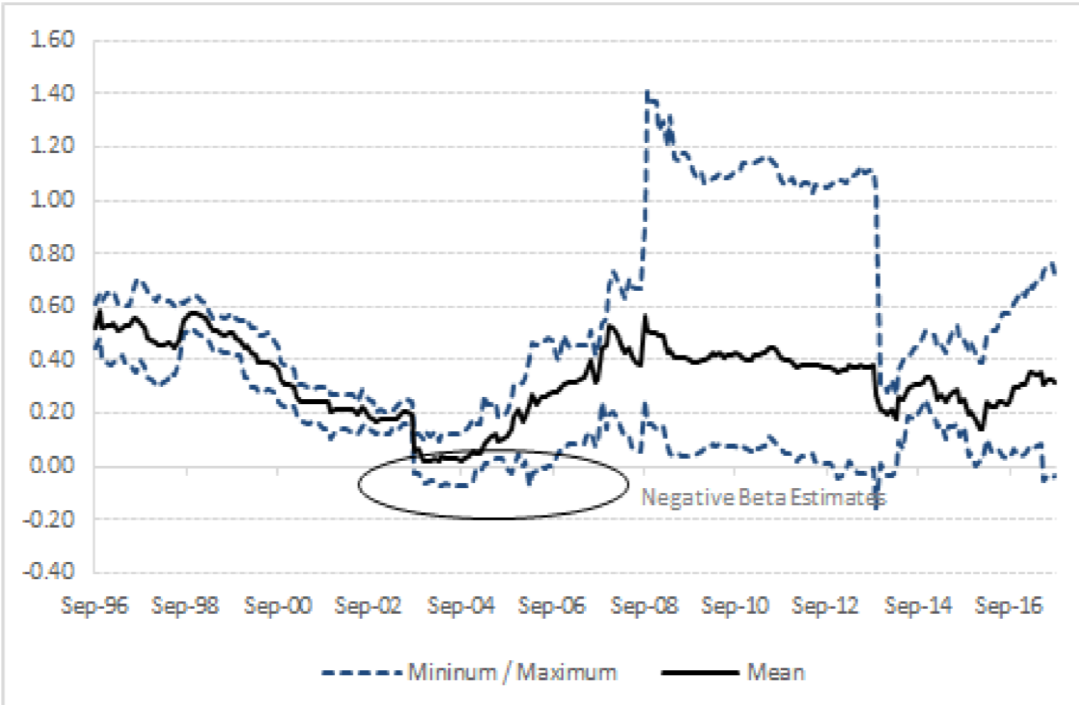
2. I next turn to the evidence provided by Mr. Hevert in the 2018 proceedings. Chart 20 and Chart 21 on page 79 of Mr. Hevert's evidence depict the historical raw beta estimates for his Canadian Utility sample over the 1995-2017 period using five years of weekly data (Chart 20) and using five years of monthly data (Chart 21). I reproduce these two charts below.

Chart 20: Canadian Utility Proxy Group Unadjusted Beta Coefficients – Weekly Return over Five Years



[41] For future reference, I note that adjusted betas (i.e., Bloomberg, Value Line, etc.) are determined using the following equation, which adjusts a raw (unadjusted) beta towards "1": Beta(adjusted) = (2/3)(Raw Beta) + (1/3)(1).

Chart 21: Canadian Utility Proxy Group Unadjusted Beta Coefficients – Monthly Return over Five Years



Mr. Hevert confirmed in response to HEVERT-UCA-2017NOV21-026(c) that the following statistics for Charts 20 and 21 are correct:

Chart 20 (weekly data): Average – 0.38 / Median – 0.43 / Max – 0.71

Chart 21 (monthly data): Average – 0.34 / Median – 0.37 / Max – 0.61

Notice that the reported averages here of 0.34 and 0.38 are consistent with those provided in Dr. Villadsen's 2016 rebuttal evidence between 0.31 and 0.35 evidence. Also, similar to the charts provided in Dr. Villadsen's 2016 rebuttal evidence, these two charts (i.e. Charts 20 and 21) clearly show that nowhere during this entire 22-year period do the Canadian Utility beta estimates even come close to 1.0, with maximum values of 0.71 and 0.61. This evidence confirms the fact that it makes no sense to adjust betas toward one.

Charts 22 and 23 on page 80 of Mr. Hevert's 2018 evidence also depicts the historical raw beta estimates for his U.S. Utility sample over the 1995-2017 period using five years of weekly data (Chart 22) and using five years of monthly data (Chart 23). Mr. Hevert confirmed in response to HEVERT-UCA-2017NOV21-026(e) that the following statistics for Charts 22 and 23 are correct:

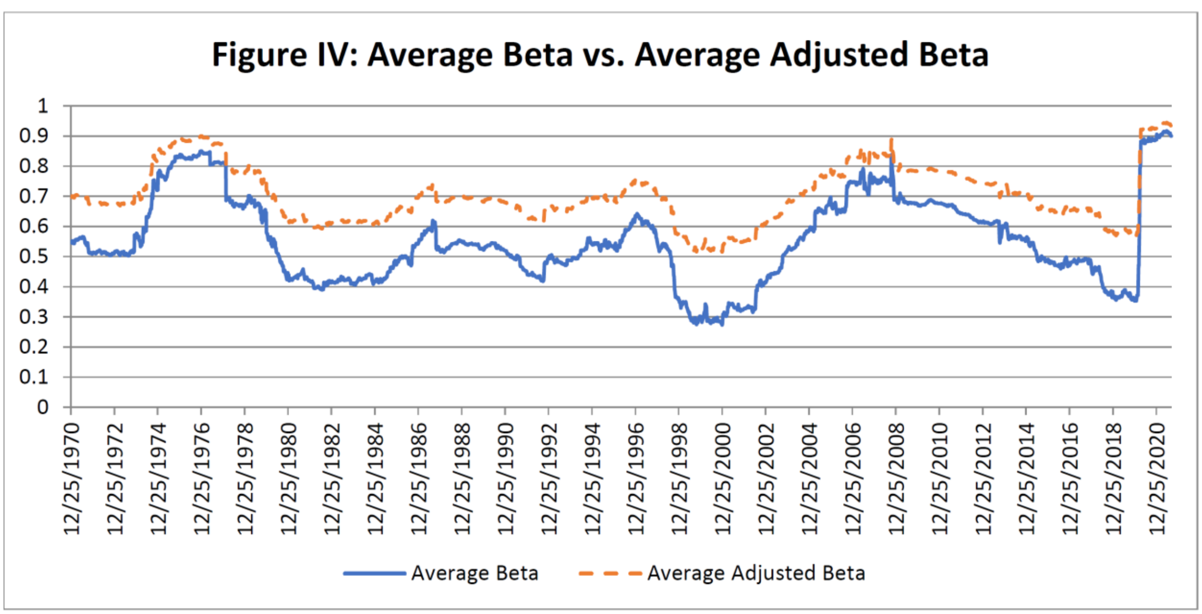
Chart 22 (weekly data): Average – 0.51 / Median – 0.52 / Max – 0.83

Chart 23 (monthly data): Average – 0.43 / Median – 0.47 / Max – 0.82

These two charts for U.S. utilities show that nowhere during this entire 22-year period do the U.S. Utility beta estimates even come close to 1.0.

The evidence above is consistent with the conclusions of Sikes (2022) regarding U.S. utility betas, who notes (pages 46-47) that in his study "Using adjusted betas instead of the appropriate unadjusted betas increased the CAPM estimate by ~100 basis points." He went on to note that this was consistent with the findings of Michelfelder and Theodossiou (2013) "who showed empirically that utility betas do not have a tendency to converge to 1.0 and concluded that the adjusted betas as reported by Value Line are not applicable for public utilities."

Sikes provided a chart (Figure IV) depicting raw versus adjusted betas for U.S utilities over a 50-year period, from 1970-2020, which I have copied below:



Source: Page 48 of Sikes (2020) – Exhibit AT.

Sikes went on to note (page 48) that: "It is undeniable based on Figure IV that the Value Line Adjustment is inappropriate. Clearly, utility betas have been consistently below 1.0 and as shown in Exhibit II of the Appendix, the historical sample suggests an average of 0.55." I would further note that the line depicting adjusted betas in Sikes' chart is **always** above the line depicting actual betas – this is the definition of a biased estimator – in this case **upwardly biased**. Since the raw or unadjusted beta is used to predict the actual relationship between market returns and security returns (in this case utility returns), using adjusted betas will provide upwardly biased estimates of betas for future returns, as it always has done historically.

Notice that the average of 0.55 noted by Sikes (2022) for U.S. utilities is higher than the Canadian average noted above, which is closer to 0.35. Charts 22 and 23 of Mr. Hevert's evidence also show that the U.S. utility beta estimates have consistently exceeded those of Canadian utilities, with long-term averages of 0.51 and 0.43, which are 34.2% and 26.5% higher than his corresponding Canadian weekly and monthly average estimates of 0.38 and 0.34. In fact however, this difference in Canada-U.S. beta estimates understates the true difference in risk, since the estimated betas are "levered" betas (i.e., they do not adjust for differences in the leverage ratios of the companies used to estimate them). The reason this is misleading is because U.S. utilities display higher levered betas, despite the fact they should be expected to have lower leverage ratios on average (i.e., since U.S. utilities have higher allowed equity ratios).

To illustrate the impact that leverage differences would make, I note from Figure 28, page 76 of Dr. Villadsen's evidence in the 2018 GCOC proceeding that the 2017 allowed equity ratios for U.S. Natural Gas, Electric and Electric T&D are 48.7%, 48.6% and 48% respectively, versus 39.6% for all Canadian utilities. These suggest debt-equity (D/E) ratios of (51.5/48.5) for U.S. utilities and (60/40) for Canadian utilities. Using the Hamada equation used by Mr. Hevert in his 2018 evidence (page 103, equation [12]), and the 27% tax rate that he used in applying this equation, we can obtain the following equivalent "relevered" U.S. beta estimates that can be compared to the Canadian levered beta estimates of 0.38 and 0.34:

U.S. (monthly) beta estimate = 0.43:

1st: Unlever accounting for U.S. leverage ratios:

$$B(\text{unlevered}) = B(\text{levered}) / \{[1 + (1 - \text{Tax rate})](D/E)]\}$$

$$= 0.43\{[(1 + (1 - .27)](51.5/48.5)] = 0.43/\{1.837\} = 0.234$$

2nd: Relever accounting for Canadian leverage ratios:

$$B(\text{levered}) = B(\text{unlevered}) \times \{[1 + (1 - \text{Tax rate})](D/E)]\}$$

$$= 0.234\{[(1 + (1 - .27)](60/40)] = 0.234 \times\{2.595\} = \mathbf{0.61}$$

U.S. (weekly) beta estimate =0.51:

1st: Unlever accounting for U.S. leverage ratios:

$$B(\text{unlevered}) = 0.51 /\{1.837\} = 0.278$$

2nd: Relever accounting for Canadian leverage ratios:

$$B(\text{levered}) = 0.278 \times\{2.595\} = \mathbf{0.72}$$

So, in fact the “comparable” U.S. beta historical averages of 0.61 (monthly) and 0.72 (weekly) are **much, much higher** than (i.e., **almost double**) the comparable Canadian beta estimates of 0.34 and 0.38, after accounting for leverage differences. The implied “unlevered” U.S. betas (0.234 monthly; 0.278 weekly) are **almost double** those for the Canadian utilities (0.131 monthly; 0.140 weekly) using D/E ratios of 0.515/0.485 for U.S. utilities and using D/E ratios of 0.60/0.40 for Canadian utilities. This historical data provides strong evidence to suggest that in determining allowable ranges for regulated Canadian utilities, the Commission should **not** consider U.S. utility beta estimates.

The examination of the historical evidence above confirms the following three important facts:

1. Canadian utility beta estimates have averaged somewhere between 0.20 and 0.40 – with **0.35** representing the best estimate.
2. Canadian utility beta estimates have never come close to one, with maximum values in the 0.6-0.8 range. Neither have U.S. utility beta estimates ever come close to one for that matter. Hence **the use of traditional adjusted betas is totally inappropriate.**

3. **U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered**.[42] This is consistent with the higher level of business risk associated with U.S. utilities.

Based on these observations, I recommend the following approach for determining reasonable beta estimates, which can be used by the Commission when they receive a wide spread in beta estimates:

1. Ensure beta estimates are from reasonable comparators – i.e., **exclude U.S. utility beta estimates**.
2. **Do not use traditional "adjusted beta" estimates,** which are based on the inaccurate assumption that utility betas gravitate towards one in the long run. If there is a desire or need for a "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35, or even 0.45, rather than toward 1.0, as is done with published betas provided by services such as Bloomberg and Value Line.
3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

As noted above, a review of the 2018 utilities' experts' evidence showed that Canadian utility beta estimates have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate. In the 2018 GCOC Decision, the Commission calculated a historical utility beta average of 0.47, based on data that excludes the 1998-2007 period, in order to discard the abnormally low estimates obtained over the 1998-2002 period. It is important to recognize that as an average, this implies approximately half of the estimates would be both below and above this estimate of central tendency. The fact that this average is so close to the 0.45 that I have

[42] For example, I show above that Mr. Hevert's historical average Canadian beta estimates of 0.34 (monthly) and 0.38 (weekly) are just over half their U.S. counterpart estimates of 0.61 (monthly) and 0.72 (weekly), after accounting for leverage differences. The implied "unlevered" U.S. betas (0.234 monthly; 0.278 weekly) are almost double those for the Canadian utilities (0.131 monthly; 0.140 weekly).

used in previous Proceedings confirms the appropriateness of the range that I used and the judgment I employed in determining my beta estimate during the 2013, 2016, 2018 and 2021 GCOC Proceedings, and which lies at the mid-point of the range of reasonable beta estimates that I have previously recommended to the Commission during those proceedings.

The top portion of Table 9 provides both weekly and monthly beta estimates for the Canadian utility sample as of December 31, 2022, as well as the seven-year average of beta estimates over the 2016-2022 period.[43] The December 31, 2022 weekly beta estimate average is **0.336**, while the average for monthly betas is **0.319**, both of which are only slightly below the long-term average beta estimate of 0.35 discussed above, and well below the 0.45 beta estimate I have used during previous Proceedings. The seven-year average weekly betas for the Canadian sample is **0.520**, while the seven-year average monthly beta estimate is **0.246** – with the weekly estimate lying above the historical average of 0.35, and the monthly beta lying well below it. The average of all four beta estimates provided for this sample is **0.355**, virtually identical to the long-term average beta estimate of 0.355. My usual beta estimate of 0.45 is reasonably consistent with all four estimates, being slightly below one of them, yet well above three of them as well as the average of all four – so I would judge it to be a conservative beta estimate.

[43] The working papers for Table 9 are appended as Exhibit K to my evidence.

TABLE 9

BETA ESTIMATES – December 31, 2022

Firm				
	Weekly Betas		Monthly Betas	
CANADIAN SAMPLE	Dec 31 / 22	2016-2022 Average	Dec 31 / 22	2016-2022 Average
Fortis	0.266	0.538	0.188	0.074
Cdn Utilities Ltd.	0.315	0.656	0.593	0.493
Hydro One	0.319	0.351	0.279	0.171
Emera	0.233	0.451	0.271	0.158
Algonquin Power	0.548	0.602	0.264	0.332
Average	**0.336**	**0.520**	**0.319**	**0.246**
	Weekly Betas		Monthly Betas	
US SAMPLE	Dec 31 / 22	2016-2022 Average	Dec 31 / 22	2016-2022 Average
Alliant Energy Corporation	0.579	0.541	0.501	0.362
Ameren Corporation	0.605	0.478	0.426	0.313
Entergy Corporation	0.599	0.633	0.632	0.474
Portland General Electric Company	0.439	0.524	0.589	0.334
Xcel Energy Inc.	0.517	0.463	0.414	0.225
ALLETE	0.690	0.637	0.732	0.441
American Electric Power Company, Inc.	0.493	0.514	0.422	0.238
Duke Energy Corporation	0.442	0.452	0.392	0.202
Evergy Inc.	0.521	0.508	0.472	0.362
Eversource Energy	0.536	0.572	0.481	0.324
NorthWestern Corporation	0.412	0.642	0.451	0.355
OGE Energy	0.627	0.722	0.672	0.656
CenterPoint Energy	0.709	0.798	0.863	0.673
CMS Energy Corporation	0.552	0.478	0.320	0.156
Sempra Energy	0.597	0.644	0.700	0.574
DTE Energy Company	0.550	0.580	0.595	0.394
Black Hills	0.630	0.638	0.524	0.467
Dominion Energy, Inc.	0.461	0.443	0.420	0.298
MGE Energy Inc.	0.514	0.476	0.684	0.443
Southern Company	0.526	0.535	0.479	0.262
Unitil Corporation	0.441	0.532	0.498	0.271

WEC Energy Group	0.467	0.457	0.379	0.146
Atmos Energy	0.603	0.531	0.584	0.336
New Jersey Resources Corporation	0.560	0.643	0.651	0.467
NiSource Inc.	0.606	0.568	0.454	0.279
Spire, Inc.	0.539	0.553	0.435	0.287
Northwest Natural Holding Company	0.290	0.468	0.536	0.405
ONE Gas Inc.	0.374	0.576	0.658	0.328
Average	**0.531**	**0.557**	**0.534**	**0.360**

Source: Bloomberg, January 5, 2023. Refer to Exhibit K.

The bottom portion of Table 9 provides both weekly and monthly beta estimates for the U.S. utility sample as of December 31, 2022, as well as the seven-year average of beta estimates over the 2016-2022 period. The December 31, 2022 weekly beta estimate average is 0.531, while the average for monthly betas is 0.534, both of which are only slightly below the 50-year average beta estimate of 0.55 determined by Sikes (2022) discussed above, and in line with Hevert's average estimates provided in the 2018 proceedings. The seven-year average weekly betas for the U.S sample is 0.557, while the seven-year average monthly beta estimate is 0.360 – with the weekly estimate lying almost exactly at the historical average of 0.55, and the monthly beta lying well below it – as was the case with the seven-year Canadian beta estimates. The average of these four estimates is 0.5 – 41% higher than the Canadian average of 0.355.

Not surprisingly based on my previous discussion, all four average U.S. utility beta estimates are higher than the Canadian estimates, and the average is 41% higher than the Canadian average. This confirms that U.S. utilities are riskier than Canadian utilities (even without taking into account the lower leverage of U.S. utilities). Based on this evidence, the longer term beta evidence discussed previously, and additional evidence that I will advance in Sections 4.3.2 and 4.3.3, I confirm that U.S. utilities are much riskier than Canadian utilities and should **not** be used as comparators. However, I would note that even these U.S beta average estimates are in line with my usual beta estimate of 0.45.

Exhibit K provides additional support that the use of adjusted betas provide upward biased estimators of the true beta. In particular, none of the 35 individual raw Canadian monthly beta estimates (i.e., five firms × 7 annual beta estimates each = 35), and none of the 196 U.S. beta estimates (i.e., 28 firms × 7 annual beta estimates each = 196) provided over the seven-year period exceed the adjusted betas – none! So clearly these adjusted beta estimates are **100% upwards biased** from the true betas. For weekly betas, Exhibit K shows that only one of the 35 raw Canadian beta estimates exceeds the adjusted beta, and just 32 of the 196 U.S. beta estimates did so. In aggregate, 1 of 70 Canadian weekly raw beta estimates (or 1.4%) and 32 of 392 weekly estimates (or 8.2%) exceeded the adjusted betas, so it is clear this is an upwardly biased adjustment. I would further note that the fact that 8.2% of U.S. adjusted weekly beta estimates are below raw weekly beta estimates versus only 1.4% for Canadian utilities provides additional support for the fact that U.S. utilities have higher betas, and are riskier.

As argued above, I will not consider the U.S. beta estimates, since I believe they are too risky to be legitimate comparators; although I would note that the U.S. estimates are nonetheless very much in line with my final beta estimate. Based on the evidence provided in Table 9 and combining it with long-term historical averages, it is obvious that a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. The current average of Canadian beta estimates I note above is 0.355, consistent with the long-term average of 0.35. In order to be consistent with my recommendations in the 2013, 2016, 2018 and 2021 GCOC Proceedings, I will use the mid-point figure of my recommended range (i.e., 0.30-0.60) of **0.45** as my best point estimate, which is above the long-term average of around 0.35, as well as the current average of 0.355.

3.2.5 Final CAPM Estimates

While government bond yields have risen over the last year, they still remain low, both in absolute terms and by historical standards. A-rated Canadian utility bond yield spreads were sitting at 158 bp as of January 19, 2023, 29 bp above the long-term average spread of 139 bp. While this difference from the average spread is relatively small, I will adjust for it as I have in previous proceedings. Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian utilities.[44] Consistent with this research, I will add half of the “above average” yield spread (i.e., (0.158 - 0.139)/2), or 0.095%, to my CAPM estimate to account for this time varying risk premium.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous Commission decisions, and consistent with long-term estimates. Combining these items, I provide my CAPM estimates for the required equity return for the average regulated Alberta utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests an ROE of **5.7%**.

TABLE 11

CAPM ESTIMATES – 2020-2021

Estimate	RF (%)	MRP (%)	Beta	Spread Adjust. (%)	Financial Flex. (%)	Ke (%)
CAPM Best Estimate	2.85	5.0	0.45	0.095	0.50	**5.7%**

The CAPM parameters used (i.e., RF of 2.85%, MRP of 5% and the spread adjustment of 0.095%) imply a required return on the entire market of 7.95%, which is above the long-term market return expectations of finance professionals of 7.2% provided in Table 8, while it is in line with the long-term real returns on Canadian stocks. It is also slightly above my best estimate of 7.5% for the long-term expected return on the market that I discussed previously.

3.3 Discounted Cash Flow Estimates

3.3.1 DCF Model Overview

The Commission has appropriately taken DCF estimates into account in making previous decisions as to the appropriate ROE. I use two approaches and apply the DCF model using data as at the end of 2022 to:

[44] Refer to: A. Garcia and J. Yang, “Understanding Corporate Bond Spreads Using Credit Default Swaps,” Bank of Canada Review, Autumn 2009. This article is appended as Exhibit BI to this evidence.

1. find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the average company in the market; and,
2. apply the models at the industry level using numbers that are representative of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The Dividend Discount Model ("**DDM**") is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely. The constant-growth model can be represented as:

$$\text{Price} = D_0(1 + g) / (Ke - g) = D_1/(Ke - g)$$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/\text{Price})\times(1 + g) + g$$

3.3.2 Market DCF Estimates

Table 1 showed that real GDP growth has averaged 2.3% over the 1992 to 2021 period, which provides one potential estimate of long-term growth that could be used in the single-stage model, since one might expect long-term growth for the overall market to gravitate towards this figure. Similar assumptions are commonly made by financial analysts. The average forecast for real GDP growth for Canada for 2023 provided in Table 3 was 0.97%, which is the same as the 1% forecast from the Bank of Canada in its January 2023 MPR. The Bank further predicted 1.8% real GDP growth for 2024. The mid-point of these future estimates of real growth is 1.4%, which provides another reasonable estimate of future Canadian economic growth. Of course, we are trying to estimate a "nominal" required rate of return, so we should use nominal GDP growth as "g." We can estimate nominal growth rates by applying the 2% Bank of Canada inflation target, which generates the following long-term nominal Canadian GDP growth rate estimates that correspond to the two real growth rates noted above: 4.3% and 3.4% - 4.3% where 3.85% represents the mid-point of these figures. These growth rates are in line with those used by security analysts when they use single-stage growth models to value securities (i.e., they usually use numbers in the 3-5% range *when* they use single period models).

The dividend yield for the S&P/TSX Composite Index as of December 31, 2022 was 3.28%. This is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent 12-month period. Substituting the average nominal GDP growth estimate of 3.85% noted above into the single-stage DDM equation provided above, we get the following estimate for the implied equity return for the market as a whole for 2020:

$$Ke = (0.0328)\times(1.0385) + .0385 = 0.0726 \text{ or } \mathbf{7.26\%}$$

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, this estimate seems to be reasonable. It is only slightly below my long-term forecast for expected market returns of 7.5%, and is almost identical to the average forecast for future Canadian stock market returns of 7.2% found in Table 8.

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

I consider the long-term GDP growth forecasts that translated into a 3.4% nominal GDP growth rate as my short-term growth rate (g_S), and use the historical long-term GDP nominal growth rate average of 4.3% as the long-term growth rate (g_L). Assuming it takes four years to get back to this long-term expected growth rate, then we would use H = 2, which provides an estimate for Ke of 7.66%. If we assume that this return to long-term growth takes longer (say 8 years), then H = 4, and we get an estimate for Ke of 7.60%. The mid-point of these two estimates is 7.63%.

Combining the results from the two DDM models, we get estimates for Ke for the market in the 7.26-7.63% range. Taking the mid-point of the single-stage DDM estimate of 7.26% and the 7.63% estimate from the H-model, we arrive at 7.45% as my best estimate of the implied return on the market using DCF models, which is virtually identical to my 7.5% estimate for future market returns. DCF models will work better in aggregate than for Canadian utilities, which leaves us with the issue of how to adjust these figures into a reasonable implied return for utilities that possess considerably less risk than the average company in the market. At minimum, we could say that the market DCF estimates suggest that utility returns should be ***lower than 7.45%***.

3.3.3 Alberta Utility DCF Estimates

I will now apply both of the DCF models discussed above to the utilities' samples. Of course, determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's **sustainable growth**

rate, which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the ROE, as shown below:

g = (1 – payout ratio) × ROE.

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures that are generally close to allowed ROEs, which do not usually fluctuate by large amounts.

Table 11 below includes summary statistics on dividend yield, payout ratios and ROE for both the Canadian and U.S. utility samples that were included in Table 9. This data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using our two DCF models. Panel A reports the average, median, maximum and minimum figures for the Canadian sample for the December 2022 dividend yield ("**DY**"), the 2016-2022 average DY, the 2022 and 2016-22 average payout ratios[45], and the 2021 and 2016-2021 average for ROEs.[46] Panel B reports the same statistics for the U.S. sample. The working papers for Table 11 (and Table 12) are appended to my evidence as Exhibit L.

The summary statistics included in Panel A of Table 11 appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. High dividend yields in the 4-5% range and corresponding high payout ratios in the 75-81% range are in line with historical figures, and are consistent with the high dividend paying nature of such profitable, slow growing firms. The ROE averages in the 6.1-8.2% range are also reasonable. The statistics for the U.S. sample included in Panel B are also reasonable; although it is noteworthy that dividend yields around 3.4% and corresponding payout ratios in the 67-69% range are well below the

[45] Payout ratios were "capped" at 100% to control the influence of extreme payouts on averages - this process obviously had no effect on the reported medians.
[46] Unfortunately the 2022 ROEs were not available at the time of writing, so I was forced to use the 2021 ROEs.

corresponding figures for Canadian utilities, indicating U.S. firms maintain lower dividend payouts than Canadian utilities. The U.S. sample ROE averages in the 8.7-9.7% range are higher than those for the Canadian sample, which is consistent with the observation that allowed ROEs are generally higher in the U.S. than in Canada.

TABLE 11

DCF INPUT ESTIMATES – 2016-2022 FIGURES

Panel A (Canadian Sample)	**DY (Dec 22)**	**2016-2022 Avg DY**	**2022 Payout**	**2016-2022 Avg Payout**	**2021 ROE**	**2016-2021 Avg ROE**
Average	5.32	4.40	81.18	75.20	5.93	8.15
Median	4.77	4.60	76.81	78.47	6.04	7.20
Max	9.79	5.27	100.00	88.79	7.09	11.49
Min	3.00	3.64	64.50	51.23	4.79	5.93
Panel B (U.S. Sample)						
Average	3.39	3.36	68.80	66.70	9.72	8.72
Median	3.33	3.32	64.22	68.58	8.84	9.11
Max	4.48	5.78	100.00	69.90	22.65	9.72
Min	2.23	1.99	48.83	59.67	3.98	6.32

Data Source: Morningstar at www.morningstar.ca.

It is difficult to find "typical" or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 12 provides estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 11. These are calculated using the formula above (i.e., g = (1 – payout) × ROE)). Column 2 uses the average and median figures for the 2021 ROE and the 2022 payout figures, while column 3 uses the averages and medians for the 2016-21 ROEs and the 2016-2022 payout figures. The median and average growth rates range from 1.12% to 2.02%, with the average of the two averages being 1.57% and the average of the two medians sitting at 1.48%. The mid-point of these two estimates is 1.525%. This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.45-4.3% range discussed previously. The average and median growth rates for the U.S. sample are higher at 3.15% and 3.05% respectively, reflecting both the lower payout ratios and the higher ROEs of U.S. utilities.

TABLE 12

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

1	**2**	**3**	**4**	**5**
	Implied g (2022)	**Implied g (16-22)**	**Implied Ke (2022 g and 2022 DY)**	**Implied Ke (16-21 g and 7-year DY)**
PANEL A: Canadian Sample				
Average	1.12	2.02	6.50	6.51
Median	1.40	1.55	6.24	6.22
Average of 2 averages g = 1.57%			**Average of 2 averages Ke = 6.51%**	
Average of 2 medians g = 1.48%			**Average of 2 medians Ke = 6.23%**	
PANEL B: U.S.				
Average	3.40	2.90	6.91	6.36
Median	3.24	2.86	6.67	6.27
Average of 2 averages g = 3.15%				**Average of 2 averages Ke = 6.64%**
Average of 2 medians g = 3.05%				**Average of 2 medians Ke = 6.47%**

The final two columns in Table 12 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 11). Recall this formula can be represented as follows when we begin with the dividend yield based on dividends over the previous 12 months: $Ke = (D_0/Price)\times(1 + g) + g$.

The Canadian sample Ke estimates lie in a tight range from 6.22% to 6.51%. The average of the two Ke estimates determined using averages is 6.51%, while the average of the two medians is 6.23%. I will assign a best estimate single-stage DDM estimate at the mid-point of **6.37%**, 57 bp above my single-stage DCF estimate of 5.8% in my 2020 evidence. This estimate is 0.89% below my 7.26% single-stage growth DDM estimate for the market, which is low but reasonable since regulated utilities are considerably less risky than the average company. If we add 50 basis points for flotation costs, we end up with a best estimate of **6.87%**. While I do not use the U.S. Ke estimates, the overall average would be 6.55% (before flotation costs adjustments), so very much in line with my 6.37% estimate based on the Canadian sample.

While I believe these estimates are reasonable, as are the growth rates upon which they are based, the Commission expressed concerns in 2018 regarding the use of low growth rates, that could be negative real growth rates based on inflationary expectations. I disagree with this assertion regarding the reasonableness of these growth estimates. For example, as noted in an information response during the 2018 Proceeding (UCA-AUC-2018JAN26-012):

> Dr. Cleary notes that the average long-term sustainable growth rate he uses in his single-stage model is 1.9% and his average short-term estimate used in the H-model is 1.0% while his long-term sustainable growth rate is 2.8%. These estimates are very reasonable. For example, they are in line with the long-term (i.e., terminal) growth rates used by analysts in some of the equity analyst reports provided by the utilities during the 2018 Proceeding. Some of the analysts' "best" estimates of terminal growth rates are reported below, which are in the **0.0%-2.0% range and average 1.38%**.
>
> Fortis Inc.: BMO =1.0%; CIBC = 2.0%.
>
> Canadian Utilities: BMO = 1.5%;
>
> AltaGas: BMO = 0.0%; CIBC = 2.0%.
>
> Enbridge Inc.: CIBC = 1.8%.
>
> Hydro One Limited: CIBC = 1.39%.

It is also important to recognize, as noted by the Commission in the 2018 GCOC Decision:

> The Commission recognizes that the utilities are, as Dr. Cleary stated in his evidence, essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.[47]

[47] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 92, para. 438.

Further, even the assumption of nominal GDP growth (i.e., average growth) estimated previously as 3.45-4.3% is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for dramatic growth, as also acknowledged previously by the Commission, in the 2013 GCOC Decision:

> However, the Commission is also mindful that, as both experts acknowledged, **the GDP growth rate may be an ambitious target** for long-run earnings growth in respect of low-risk, mature, utilities.[48]

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the implied growth rates determined using 2022 payout ratios and 2021 ROEs, which are reported in column 2 of Table 12. I then denote as g_L the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 12. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 13 below. The working papers for Table 13 are appended to my evidence as Exhibit M.

[48] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].

TABLE 13

H-MODEL ESTIMATES

Canadian Sample		
	H=2	**H=1**
Current D0/P0	0.0532	0.0532
gs (current sustainable g)	0.0126	0.0126
gL (long-term sustainable g)	0.0179	0.0179
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0126	0.0126
g1	0.0139	0.0152
g2	0.0152	0.0179
g3	0.0165	0.0179
g4	0.0179	0.0179
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0715**	**0.0717**
AVERAGE	**0.0716**	
U.S. Sample		
Current D0/P0	0.0339	0.0339
gs (current sustainable g)	0.0332	0.0332
gL (long-term sustainable g)	0.0288	0.0288
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0332	0.0332
g1	0.0321	0.0310
g2	0.0310	0.0288
g3	0.0299	0.0288
g4	0.0288	0.0288
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0640**	**0.0639**
AVERAGE	**0.0640**	

As before, I will use only my Canadian sample estimates for Ke, for the reasons discussed above. The Ke estimates for the Canadian sample are 7.15% and 7.17%, with a mid-point of 7.16%. Combining this mid-point with a 0.50% allowance for flotation costs, we get an H-model estimate of **7.66%**. The Ke estimates from the H-Model are 0.79% higher than the averages derived using the single-stage model. This is largely driven by the use of the 2022 dividend yield of 5.32%, which is almost 1% higher than the seven-year average dividend yield of 4.40%. It is also driven by the fact that the model implicitly assumes that growth rates will gravitate to longer term average rates, which were higher at 1.79% than were the implied short-term growth rate of 1.26% using 2022 data only. By contrast, the U.S. H-model estimate of 6.4% is below the U.S. single-stage estimate of 6.55%, since the 2022 dividend yield of 3.39% is very close to the seven-year average of 3.36%, while the seven-year growth rate (used as the long-term growth rate) of 2.90% is actually lower than the 2022 (short-term) growth rate of 3.4%, so growth would be expected to decline from the implied short-term growth rate.

My DCF analysis suggests a 7.45% required return on the market with a range of 7.26-7.63%. As discussed previously, this estimate is virtually identical to my market return estimate of 7.5% and is slightly above current estimates of finance experts of 7.2%. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return of 6.87% using the single-stage model, and 7.66% using the H-model. Weighting these two estimates equally gives me a final DCF estimate of 7.26%. However, this estimate is only 0.7% below my DCF estimate for the market (if we also adjusted the market estimates 50 bp for flotation costs to the 7.45% estimate), so it seems too high for below-average risk utilities relative to overall expected market returns, and also as discussed above it is driven by the high H-model estimate, which is 0.79% higher than the single-stage estimates and is primarily due to the abnormally high DY at the end of 2022. Due to these inconsistencies with respect to my H-model estimate, I have chosen to weight this estimate 1/3rd and the single-stage estimate 2/3rd, which makes my final DCF estimate **7.13%,** which implies a more reasonable difference of 0.83% from my DCF estimate for the market (after adding 0.50% for flotation costs) – even though the difference is still on the low side.

3.4 Bond Yield Plus Risk Premium Estimates

The BYPRP approach adds a risk premium (generally in the 2-5% range) to the yield on a firm’s outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[49] and by over 50 percent of Canadian CFOs.[50]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable *market-determined* bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

This approach provides useful reasonableness checks on CAPM and other estimates, and employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s. In fact, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta.

The first step is to obtain an estimate of the cost of long-term yields on a typical utility. As of January 19, 2023 the yield on long-term A-rated Canadian utility bonds was 4.43% according to the Bloomberg data used to construct Figure 3. The January 3, 2023A-rated yield figure of 4.88%, before these yields dropped 45bp was close to the yields on outstanding Canadian

[49] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. Appended to my evidence as Exhibit AU.

[50] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" Multinational Finance Journal 15-3, 2011. Appended to my evidence as Exhibit AW.

utility bonds on the same date. For example the following bid and ask yields were observed as of January 3, 2023 (according to Bloomberg):

Description	S&P	DBRS	Moody's	Maturity Date	Seniority	Bid Yield	Ask Yield
Fortis Alberta Inc	A-	A(low)	Baa1u	10/2052	SNR Unsec	4.861	4.822
Fortis BC Inc		A(low)	Baa1	03/2052	SNR Unsec	5.032	4.974
CU Inc	A-	AH		09/2051	SNR Unsec	4.823	4.761
Enbridge Gas Inc	A-	A		09/2051	SNR Unsec	4.881	4.825
Hydro One Inc	A-	A(high)	A3	09/2051	SNR Unsec	4.736	4.617

This evidence implies that 4.43% is a reasonable starting point for my BYPRP estimate, as presumably the yields for the utilities noted above would also have similarly declined since January 3, 2023.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of 2.5%.[51] Combining this information, I obtain the following estimate for Ke according to this approach: Ke = 4.43 + 2.5 = **6.93%**

If we add 50 bp for flotation costs, we end up with a Ke estimate **7.43%**. This is on the high side given my market estimate of 8% (if we add 0.50% to my raw market estimate of 7.5%). It is also well above my CAPM estimate of 5.7% and my DCF estimate of 7.13%.

3.5 Price-to-Book Ratios and Equity Returns

Table 11 reported a 2021 average ROE for the 5 Canadian utilities in the Canadian sample, with a 2016-2021 average of 8.15%. ROE data that will be provided in Tables 15 and 16

[51] For example, Exhibit BJ provides an example of implementing the BYPRP approach for IBM from the CFA curriculum, where a risk premium of 2.75% is added to cost of IBM's debt. Clearly IBM is riskier than a regulated A-rated utility, so 2.5% is very reasonable by comparison.

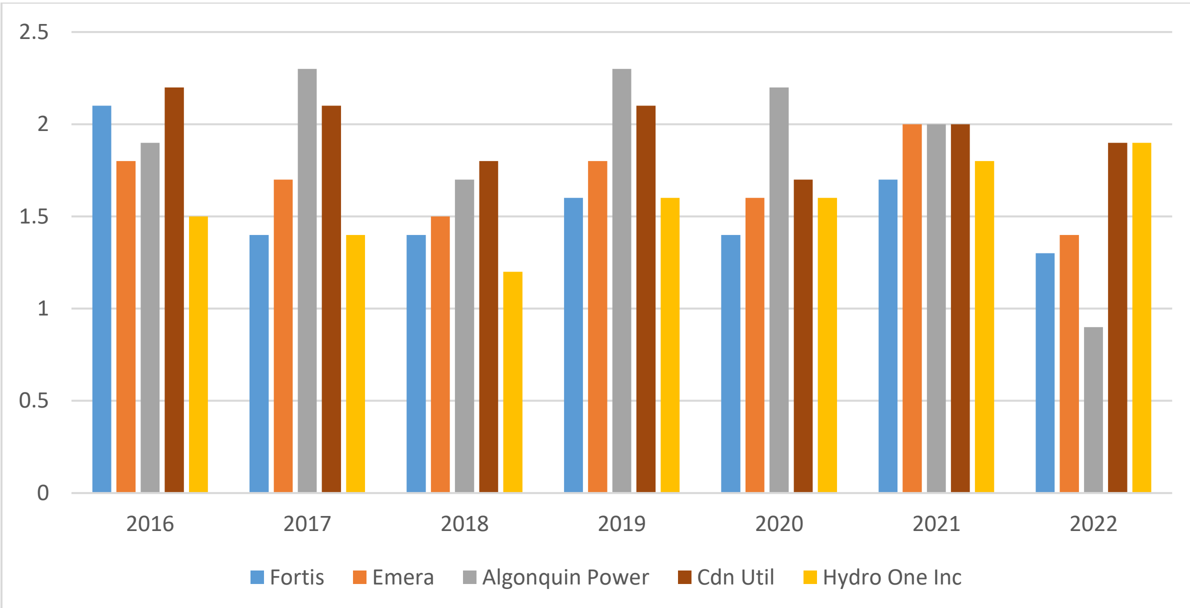
suggest that Alberta utilities earned an average ROE of 9.44% over the 2005-2021 period, with a 2021 average of 9.27%. These are higher than for the Canadian sample, and are very healthy numbers, considering that we know they are much less risky than the average Canadian company, beyond utilities. In fact, the reported ROE numbers for Alberta utilities are well above the required return estimates (before adding flotation costs) determined using the CAPM, DCF and BYPRP approaches, with best estimates of 5.2%, 6.6% and 6.9% respectively. All of this suggests that Alberta utilities would make attractive investments. Certainly, from an investor's point of view, low-risk utilities that have regulated returns that exceed *required* rates of return based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 5.2% figure that was determined above. If the utility earned the currently allowed ROE of 8.5%, then that investor would surely be pleased, and if they earned the actual 2021 average of 9.3% that would be even better. Of course, this does not mean that the actual return on the stock was 8.5% or 9.3%; however, there is an obvious relationship between the two. I examine this relationship below by reference to price-to-book ("**P/B**") ratios and stock returns.

I begin by considering the P/B ratios over the 2016-2022 period for the Canadian and U.S. utility samples examined previously in the DCF analysis. The individual P/B ratios for the Canadian sample are presented in Panel A of Figure 14. It is obvious from the chart that almost all of the ratios are above 1 throughout the entire period, with the exception of the P/B ratio for Algonquin in 2022. Panel B presents the P/B ratios for the U.S. sample over the same period, and none of the 196 individual P/B ratios was less than one. Table 14 provides summary statistics for the two samples. Panel A shows that the average P/B ratio for Canada ranged between 1.48 and 1.90 over the period, averaging 1.74. Panel B shows that the average P/B ratio for the U.S. sample was greater than the Canadian average every year, ranging from 1.96 to 2.36 and averaging 2.10 over the period. The working papers for Figure 14 and Table 14 have been appended to my evidence as Exhibit N.

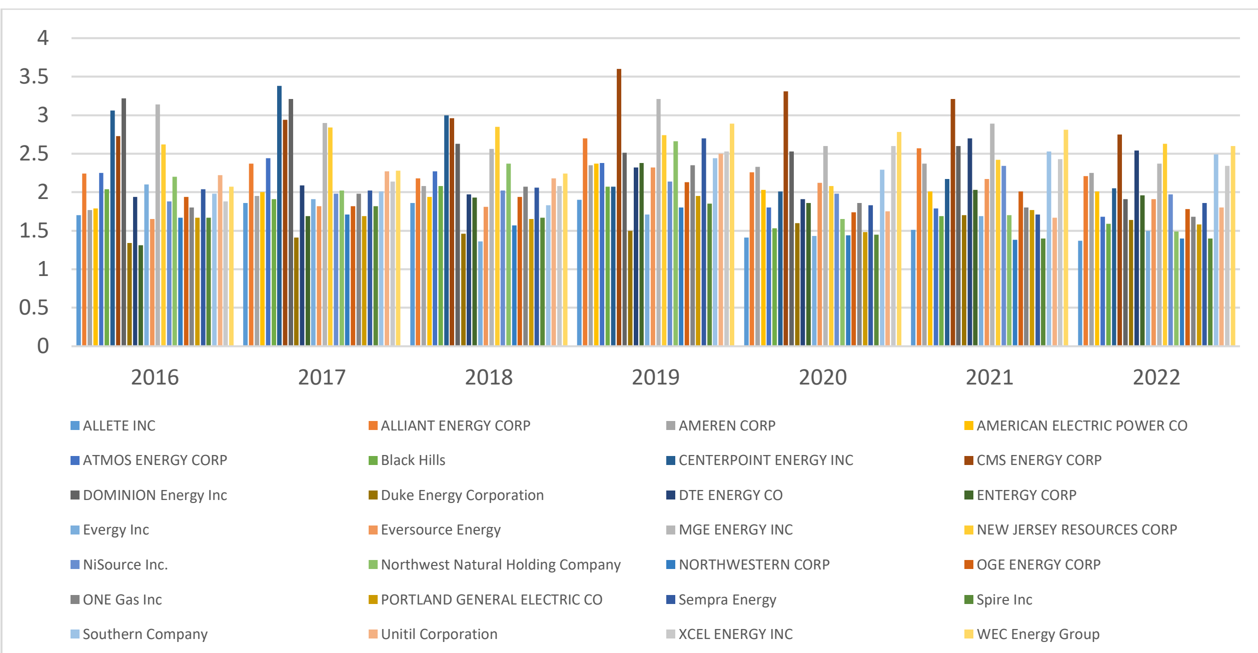
FIGURE 14

UTILITY P/B RATIOS – 2016-2022

Panel A: Canadian Sample



Panel B: U.S. Sample



Data Source: Morningstar at www.morningstar.ca.

TABLE 14

P/B RATIO SUMMARY STATISTICS (2016-2022)

Panel A: Canadian Sample

All Utilities	2016	2017	2018	2019	2020	2021	2022	7-yr Avg
Average	1.90	1.78	1.52	1.88	1.70	1.90	1.48	1.74
Median	1.90	1.70	1.50	1.80	1.60	2.00	1.40	1.70
Max	2.20	2.30	1.80	2.30	2.20	2.00	1.90	2.10
Min	1.50	1.40	1.20	1.60	1.40	1.70	0.90	1.39

Panel B: U.S. Sample

All Utilities	2016	2017	2018	2019	2020	2021	2022	7-yr Avg
Average	2.07	2.16	2.09	2.36	1.99	2.11	1.96	2.10
Median	1.96	2.005	2.065	2.36	1.885	2.02	1.91	2.03
Max	3.22	3.38	3	3.6	3.31	3.21	2.75	3.21
Min	1.31	1.41	1.36	1.5	1.41	1.38	1.37	1.39

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least “fair,” if not above fair. This is consistent with the Commission’s statement in the 2011 GCOC Decision. The Commission confirmed the usefulness of P/B ratios in the 2013 GCOC Decision, noting:

> Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company’s P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility’s awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity.[52]

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[53] $P/B = (ROE - g) / (Ke - g)$

[52] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 221.
[53] This is true if we use the following sustainable growth rate for “g” in the DDM: $g = (1 - payout) \times ROE$.

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke. This is all very intuitive – firms that earn a return on their equity above the cost of that equity will increase firm value. We can use the equation above to estimate the implied cost of equity (Ke) for given values for P/B, ROE and g. For the Canadian sample, we can examine the 2022 average ratio of 1.48 for P/B. I will use 1.51% as an estimate for "g" since it is the mid-point of the average of average growth rates of 1.57% and the average of median growth rates of 1.48% that were provided in Table 12. Calculations provided in Exhibit N show that if we used the current allowed ROE of 8.5% for Alberta utilities as our ROE input, we would get an implied Ke figure of 6.24%, while if we used the "actual" earned ROE for Alberta utilities in 2021 according to the Rule 005 reports of 9.21%, the implied Ke would be 6.76%. If we instead used the average 2021 ROE of 5.93% for the Canadian sample as our ROE input (as per Table 11), we would get an implied Ke figure of 4.50%, while if we used the 2016-21 average ROE of 8.15% (as per Table 11), the implied Ke would be 6.00%. For the U.S. sample, we can use the 2022 average ratio of 1.96 for P/B and 3.1% for "g" (i.e., the mid-point of the average of average growth rates of 3.15% and the average of median growth rates of 3.05% that were provided in Table 12). If we used the current allowed ROE of 8.5% for Alberta utilities as our ROE input, we would get an implied Ke figure of 5.85%, while if we used the average 2021 ROE of 9.72% for the U.S. sample, we would get an implied Ke figure of 6.48%, while if we used the 2016-21 average ROE of 8.72%, the implied Ke would be 5.97%.

Both the Canadian and U.S. implied Ke estimates above are very much in line with my final ROE estimate for Alberta utilities of 6.25% (before adding 0.5% for flotation costs). While I do not assign any weight to this estimate for purposes of determining Ke, the bottom line of this discussion is that the P/B ratios for utilities reported above indicate that Canadian utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time. This is important **market-based** information that supports my Ke estimates, and confirms that Canadian (and U.S.) utilities earn ROEs well in excess of their required equity return.

3.6 Summary of ROE Calculations

I have weighted all three estimates equally, as I did in my 2013, 2016, 2018 and 2020 evidence, because all three methods are used in practice. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to the DCF approaches to estimating Ke, they were used by:[54]

- only 15% of U.S. CFOs - versus over 70% for CAPM;[55]
- about 12% of Canadian CFOs - versus close to 40% for CAPM.[56]
- Not widely used, while CAPM was used by the majority of investors.[57]

CAPM is also more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also gave equal weighting to the BYPRP approach which is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for both borrowing rates and risk. In fact the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned earlier. Thus the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such it is intuitively sound.

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[54] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."
[55] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243.
[56] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011.
[57] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32.

Based on an equal weighting of the three approaches, I determine the following best estimate for Alberta utility ROEs:

Ke = (1/3)(5.7) + (1/3)(7.13) + (1/3)(7.43) = **6.75%**

This estimate is very reasonable when compared to expected long-term overall stock market returns in the 6-9% and a long-term expected market return of 7.5% (without any flotation charges added), when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 6-9% range are consistent with current long-term forecasts by market professionals (which averaged 7.2%) and with historical long-term real stock returns.

4 CAPITAL STRUCTURE ISSUES

4.1 Background

As was the case in prior GCOC proceedings, recent debt rating reports identify **low business risk** as the #1 strength for Alberta operating utilities. Consider for example the following information obtained from 2022 debt rating reports for Alberta utilities:

1. Fortis Alberta:
    a. S&P (October 2022):
        i. A- Stable, with Business Risk rated as "Excellent"
        ii. #1 Strength "Low-risk, regulated electricity distribution utility operator in Alberta. The company has minimal exposure to nonutility operations."
    b. DBRS Morningstar (December 2022):
        i. A(low) Stable
        ii. #1 Strength "Low business risk"

2. Apex:
    a. DBRS Morningstar (December 2022):
        i. BBB(high) Stable
        ii. #1 Strength "Stable cash flows underpinned by regulated utilities and contracted power assets."
3. CU Inc.:
    a. DBRS Morningstar (August 2022):
        i. A(high) stable
        ii. #1 Strength "Low-risk regulated business with supportive cost-recovery and forecast-test regulation"
    b. S&P (August 2022)
        i. A- Stable with Business Risk rated as "Excellent"
        ii. #1 Strength "CU Inc. (CUI) focuses on low-risk, regulated electricity and natural gas transmission and distribution operations with strong management of regulatory risk."
4. ALtaLink LP:
    a. DBRS Morningstar (August 2022)
        i. A stable
        ii. #1 Strength "Low business risk"
    b. S&P (May 2022)
        i. A Stable with Business Risk rated as "Excellent"
        ii. # 1 Strength "A relatively lower-risk electricity transmission company."
5. AltaLink Investments, L.P.:
    a. DBRS Morningstar (August 2022)
        i. A(low) stable

            ii. #1 Strength "Low business risk"

   b. S&P (November 2022)

      i. A Stable with Business Risk rated as "Excellent"

      ii. # 1 Strength "Owns low-risk electricity transmission utility AltaLink L.P. (ALP)."

6. EPCOR:

   a. DBRS Morningstar (October 2022)

      i. A(low) Stable

      ii. #1 Strength "Low business risk"

   b. S&P (September 2022)

      i. A- Stable with Business Risk rated as "Excellent"

      ii. # 1 Strength "EPCOR is a low-risk and rate-regulated electric, natural gas, and water-distribution utility operator."

7. ENMAX:

   a. DBRS Morningstar (July 2022)

      i. BBB (high) Stable

      ii. #1 Strength "Low-risk regulated electricity operations in Alberta and Maine"

   b. S&P (July 2022)

      i. BBB- Negative outlook with Business Risk rated as "Strong"

      ii. # 1 Strength "About two-thirds of cash flow derived from stable, regulated electric utility operations"

At the time I presented my 2020 evidence, the debt rating reports included similar statements, as they did during Proceedings previous to that. For example, 2019 debt rating reports noted low business risk as the #1 strength for Alberta operating utilities, with DBRS reports for EPCOR, Fortis Alberta and AltaLink, LP (as well as for AltaLink Investments, LP) all listing

"Low business risk" as the number 1 strength for these utilities. The number one strengths reported in reports for three other utilities at the time echoed this sentiment, with a slight variation in the wording. For ENMAX, the number 1 strength was listed as: "Low-risk regulated electricity operations in Alberta." For CU Inc., it was listed as: "Low-risk regulated businesses." And for AltaGas Canada Inc., now Apex Utilities Inc., the #1 strength was listed as: "Stable cash flows underpinned by regulated utilities and contracted power assets."

I concur with the current and previous assessments – regulated Alberta operating utilities possess low business risk. Mr. Bell's evidence provides strong support for this assertion. This is what one would expect for mature regulated transmission and distribution utilities operating virtual monopolies in a supportive regulatory environment in which they are able to pass on legitimate costs to customers. My empirical analysis in the next section confirms that Alberta utilities continue to operate in a low risk environment that enables them to consistently earn well above their allowed ROEs with very little volatility in these realized returns.

4.2 A Quantitative Review of Alberta Utilities' Performance

A compelling way of reviewing the performance of Alberta utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities – "where the rubber hits the road," so to speak. Table 15 provides such a comparison of the reported ROEs by Alberta utilities in their Rule 005 reports with the allowed ROEs over the 2013-2021 period; however the figures for the years 2005-2021 are included in the working papers for Tables 15 and 16, which have been appended to my evidence as Exhibit O. The yearly average and median figures show that Alberta utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average reported ROE was a mere 0.18% below the allowed ROE, while the median equalled it. We get a similar message if we look at the weighted average ROE ("**Wt Av ROE"**). This is estimated by weighting each utility according to its average revenue over the entire 2005-2021 period, relative to total revenue across all utilities over the entire period, which effectively gives larger weight to the larger utilities.[58]

[58] The corresponding weights are reported in Table 16.

TABLE 15

ALBERTA UTILITIES REPORTED ROEs (2013-2021)

	2021	**2020**	**2019**	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**
Fortis Alberta	10.23%	10.13%	10.60%	8.90%	9.32%	9.70%	11.12%	9.77%	9.49%
ATCO Elec Dist	12.85%	9.82%	11.21%	8.21%	13.21%	13.03%	9.90%	9.74%	10.99%
ATCO Gas	11.81%	10.80%	11.15%	11.03%	16.03%	12.93%	11.10%	10.95%	11.86%
AltaLink (Apex)	8.53%	8.63%	8.73%	7.72%	9.17%	8.21%	8.44%	8.44%	8.77%
ATCO Pipelines	9.00%	10.65%	10.49%	10.42%	10.99%	11.39%	9.80%	10.31%	10.16%
ATCO Elec Trans	8.61%	8.68%	8.98%	7.99%	9.96%	9.14%	8.23%	8.91%	9.84%
AltaGas (Apex)	9.53%	9.25%	10.26%	9.81%	9.37%	5.83%	6.16%	11.27%	12.50%
ENMAX Dist	4.29%	9.19%	9.31%	6.53%	9.64%	9.93%	6.15%	7.82%	8.05%
ENMAX Trans	7.51%	10.85%	10.87%	10.63%	10.90%	10.33%	11.48%	7.09%	5.90%
EPCOR Dist	11.44%	11.36%	11.63%	10.81%	8.02%	8.98%	10.37%	10.31%	9.74%
EPCOR Trans	8.15%	8.62%	8.75%	8.20%	5.76%	6.94%	8.90%	11.59%	7.17%
Average	9.27%	9.82%	10.18%	9.11%	10.22%	9.67%	9.24%	9.65%	9.50%
Median	9.00%	9.82%	10.49%	8.90%	9.64%	9.70%	9.80%	9.77%	9.74%
Max	12.85%	11.36%	11.63%	11.03%	16.03%	13.03%	11.48%	11.59%	12.50%
Min	4.29%	8.62%	8.73%	6.53%	5.76%	5.83%	6.15%	7.09%	5.90%
StDev	2.35%	1.00%	1.06%	1.50%	2.67%	2.25%	1.87%	1.45%	1.96%
CV(ROE)	0.253	0.102	0.104	0.165	0.262	0.232	0.202	0.150	0.206
Wt Av ROE	9.94%	9.79%	10.24%	8.95%	11.18%	10.43%	9.44%	9.61%	10.02%
Allowed ROEs	8.50%	8.50%	8.50%	8.50%	8.50%	8.30%	8.30%	8.30%	8.30%
Diff Avg	**0.77%**	**1.32%**	**1.68%**	**0.61%**	**1.72%**	**1.37%**	**0.94%**	**1.35%**	**1.20%**
Diff Median	**0.50%**	**1.32%**	**1.99%**	**0.40%**	**1.14%**	**1.40%**	**1.50%**	**1.47%**	**1.44%**
Diff Wt Avg	**1.44%**	**1.29%**	**1.74%**	**0.45%**	**2.68%**	**2.13%**	**1.14%**	**1.31%**	**1.72%**

Table 16 provides the summary statistics for each utility over the 2005-2021 period and aggregates them. These statistics show that ROEs averaged 9.44% across all utilities and all years, while allowed ROEs averaged 8.64%.[59] The last three rows in this table show that the annual averages of reported ROEs exceeded the allowed ROEs over the 17-year period by an

[59] The last two columns in Table 16 reports a commonly used measure of volatility, the coefficient of variation (CV), which will be referenced in Section 4.3.2 when I compare them to those for the U.S. sample. In this case, I use the CV of ROE – denoted as CV(ROE). The CV is determined by dividing the standard deviation (SD) of the ROE by the average ROE value. The rationale for using the CV as a measure of ROE volatility, rather than simply using the SD is that the SD is affected by the size of the average ROE. In other words, firms with larger ROEs would have higher SDs, even if they have less volatility, simply because the level of the ROEs figures used to determine the SD are higher.

average of **0.81%,** with the annual median ROEs exceeding allowed ROEs by a 17-year average of **0.93%.** The weighted annual average ROE exceeds the allowed average by an even higher margin of **1.12%,** indicating that the larger utilities have been better than average at earning above the allowed ROE. This shows that Alberta utilities operate in a low risk environment that enables them to earn attractive returns – i.e., since they are consistently able to earn their allowed ROEs or higher. This can be considered the **strongest indication that the utilities possess low risk overall**.

TABLE 16

SUMMARY STATISTICS – ALBERTA REPORTED ROEs (2005-2021)

	Weight	**Average**	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**	**CV(ROE) 2016-21**
Fortis Alberta	0.111	9.79%	9.73%	11.12%	8.79%	0.63%	0.065	0.064
ATCO Elec Dist	0.170	10.99%	10.99%	13.21%	8.21%	1.55%	0.141	0.179
ATCO Gas	0.176	11.03%	11.03%	16.03%	5.81%	2.05%	0.186	0.162
AltaLink	0.145	8.91%	8.77%	10.60%	7.72%	0.65%	0.073	0.058
ATCO Pipelines	0.058	10.36%	10.49%	11.53%	8.21%	0.86%	0.083	0.078
ATCO Elec Trans	0.120	9.23%	9.14%	10.66%	7.99%	0.74%	0.080	0.074
AltaGas	0.031	8.81%	9.25%	12.50%	4.86%	2.01%	0.228	0.177
ENMAX Dist	0.078	7.93%	8.05%	10.39%	4.29%	1.85%	0.233	0.276
ENMAX Trans	0.016	8.52%	9.84%	12.84%	0.49%	3.26%	0.383	0.130
EPCOR Dist	0.074	9.39%	9.74%	11.63%	4.48%	1.80%	0.191	0.145
EPCOR Trans	0.019	8.92%	8.75%	11.59%	5.76%	1.63%	0.183	0.150

Average	**9.44%**	9.62%	12.01%	6.06%	1.55%	**0.168**	**0.136**
Median	9.23%	9.73%	11.59%	5.81%	1.63%	**0.183**	**0.145**
Max	11.03%	11.03%	16.03%	8.79%	3.26%	0.383	0.276
Min	7.93%	8.05%	10.39%	0.49%	0.63%	0.065	0.058
StDev	1.00%	0.95%	1.62%	2.48%	0.80%		
	Average	Median	Max	Min	StDev		
Wt Avg ROE	**9.76%**	9.79%	11.18%	8.72%	0.62%		
	Average	Median	Max	Min	StDev		
Allowed ROEs	**8.64%**	8.50%	9.50%	8.30%	0.33%		
	Average	Median	Max	Min	StDev		
Diff Avg	**0.81%**	0.77%	1.72%	-0.18%	0.57%		
Diff Median	**0.93%**	0.73%	1.99%	0.00%	0.57%		
Diff Wt Avg	**1.12%**	1.14%	2.68%	-0.78%	0.80%		

4.3 A Quantitative Assessment of Alberta Utilities' Risk

4.3.1 Business Risk

My examination of the Alberta utilities' operating and regulatory environment above suggests they possess low business risk. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great of an ability to flow through increases in their costs to their customers. As noted in Section 4.1, debt rating reports consistently suggest that the Alberta utilities have low business risk.

4.3.2 Comparing the Risk of Alberta Utilities to U.S. Utilities

The purpose of the analysis in this section is to provide quantitative evidence comparing the risk of U.S. utilities that have been previously been used in the utilities' experts' evidence to that of the Alberta utilities. In particular, the evidence provided by the utilities has relied heavily on U.S. samples based on the premise that such samples are of comparable risk to Alberta utilities, and therefore require no adjustments for comparison purposes. While U.S. utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Alberta counterparts. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts, although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions.

One effective way to compare overall riskiness of Alberta utilities to their U.S. counterparts would be to compare their ability to earn their allowed ROEs, as I did for the Alberta utilities in Tables 15 and 16. Recall that Alberta utilities earned ROEs above the allowed ROEs on average every year from 2006 to 2021, and that over the entire period they earned ROEs that exceeded allowed ROEs by an annual average (median) of 0.81% (0.93%) with a revenue-weighted annual average of 1.12%. This is **bottom line empirical evidence** that Alberta utilities have low risk – i.e., "where the rubber hits the road."

It is not practical for me to undertake a comprehensive comparison of the earned ROEs to allowed ROEs for U.S. utilities since most are primarily holding companies that own several distinct operating utilities, which operate in numerous jurisdictions. Fortunately, I can point to three other sources that did conduct such analyses, all of which provide strong evidence that, unlike Alberta utilities, **the average U.S. utility earns well below their allowed ROE.**

For example, the 2018 evidence of Mr. Thygesen showed that the U.S. utilities he examined did *not* earn their allowed ROE on average.[60] For example, he found that over the 2014-2016 period the U.S. utilities included in Mr. Hevert's 2018 evidence earned on average **1.0% below** their awarded ROE, with 64% of them earning below the awarded figure. A recent Oliver Wyman report on North American utilities provides support for Mr. Thygesen's 2018 findings, suggesting that the "average utility **does not earn its allowed return on equity**."[61]

Even stronger support for this conclusion can be found in the Azgad-Tromer and Talley (2017) empirical study referenced previously. This study examined allowed ROEs versus actual ROEs using observations from all 50 states as well as four Canadian provinces over the 2005-2016 period.[62] The study contained predominantly U.S. observations, with only 18 of the 544 observations being from Canada. Hence their finding that "awarded ROEs appear to overshoot realized ROEs by between 1.5 and 1.75 percent…" can be seen as an indication that U.S. utilities do not on average earn their awarded ROE. In fact, it seems they significantly fall short of doing so, with average (median) **under-performance of 1.79% (1.45%)** according to Figure 4 of their study. This contrasts significantly with the Alberta evidence provided in Tables 15 and 16, which showed that Alberta utilities consistently earned well above their awarded ROEs over the 2005-2018 period. Clearly, it is inappropriate to compare the two groups of utility firms, which amounts to comparing apples to oranges.

[60] Exhibit 22570-X0551, 2018 CCA Evidence of J Thygesen, para. 115-144.
[61] Source: Page 10 of "North America Utilities: Still a Smart Bet for the New Grid," Oliver Wyman, 2015. Appended to my evidence as Exhibit BK.
[62] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2994314). Appended to my evidence as Exhibit AS.

Aside from referencing these sources of evidence regarding U.S. utilities' ability to earn their awarded ROE, another effective way of comparing the riskiness of Alberta utilities to that of the U.S. utility proxy groups is to compare the volatility in earned ROEs. ROE volatility is a measure of total risk (i.e., business and financial risk), since business risk influences operating income volatility while financial leverage influences net income volatility. I will use the coefficient of variation of the earned ROEs (i.e., CV(ROE)), described in footnote 58 as my ROE volatility measure, and will compare the CV(ROE) for the U.S. sample over the 2016-21 period to the ones calculated for Alberta utilities in the last column of Table 16.

Table 17 provides the summary statistics for earned ROEs for the U.S. sample over the 2016-2021 period, similar to those provided for the Alberta utilities in Table 16 over the 2005-2021 period. Table 17 shows that the reported ROEs for the U.S. utilities average 8.72% over the 2016-21 period, with a median of 9.45%. While not reported in Table 16, the 2016-21 average and median for Alberta utilities were slightly higher at 9.71% (9.81%). If we look at the last column in Table 17 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the U.S. sample to the results in the last column of Table 16 for Alberta utilities, we can see that the U.S. utilities displayed much greater volatility in ROEs than the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the U.S. utilities were 0.380 and 0.230 respectively, which are **much higher** than the corresponding average and median of 0.136 and 0.145 for Alberta utilities as reported in Table 16. The working papers for Table 17 are appended to my evidence as Exhibit P.

TABLE 17

SUMMARY STATISTICS – U.S. REPORTED ROEs (2016-2021)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
ALLETE INC	8.11%	8.30%	8.69%	7.19%	0.56%	0.069
ALLIANT ENERGY CORP	9.46%	11.33%	11.68%	1.27%	4.07%	0.430
AMEREN CORP	9.84%	10.40%	11.00%	7.32%	1.36%	0.138
AMERICAN ELECTRIC POWER CO	9.49%	10.52%	11.58%	3.46%	3.01%	0.317
ATMOS ENERGY CORP	10.65%	10.12%	13.90%	9.05%	1.75%	0.165
Black Hills	5.72%	5.68%	6.96%	4.60%	0.75%	0.131
CENTERPOINT ENERGY INC	12.82%	11.45%	43.99%	-15.06%	19.18%	1.496
CMS ENERGY CORP	14.88%	14.11%	22.65%	10.58%	4.06%	0.273
DOMINION Energy INC	10.76%	13.11%	18.89%	-1.50%	7.47%	0.695

Duke Energy Corporation	6.43%	6.98%	8.36%	2.80%	2.14%	0.332
DTE ENERGY CO	6.30%	6.42%	7.33%	4.57%	0.95%	0.150
ENTERGY CORP	3.43%	4.42%	5.16%	-1.17%	2.45%	0.713
Evergy Inc	5.68%	5.76%	6.13%	5.05%	0.42%	0.074
Eversource Energy	5.33%	5.43%	5.69%	4.86%	0.35%	0.065
MGE ENERGY INC	10.31%	10.56%	12.99%	6.99%	1.92%	0.187
NEW JERSEY RESOURCES CORP	11.63%	11.42%	17.58%	6.78%	3.45%	0.297
NiSource Inc.	4.24%	4.82%	10.31%	-1.46%	5.01%	1.182
Northwest Natural Holding Company	5.63%	8.08%	8.75%	-6.98%	6.21%	1.103
NORTHWESTERN CORP	9.34%	9.69%	10.53%	7.54%	1.14%	0.122
OGE ENERGY CORP	10.52%	10.74%	19.18%	-4.49%	8.27%	0.786
ONE Gas Inc	5.68%	5.82%	6.29%	4.77%	0.55%	0.097
PORTLAND GENERAL ELECTRIC CO	8.07%	8.40%	9.17%	5.96%	1.11%	0.138
Sempra Energy	9.63%	8.89%	19.86%	2.00%	6.31%	0.655
Spire Inc	8.20%	8.62%	10.82%	3.22%	2.67%	0.326
Southern Company	10.22%	9.96%	18.15%	3.44%	4.78%	0.468
Unitil Corporation	9.57%	9.32%	12.15%	8.41%	1.35%	0.141
XCEL ENERGY INC	10.54%	10.59%	10.78%	10.22%	0.20%	0.019
WEC Energy Group	11.66%	11.53%	13.09%	10.66%	0.87%	0.075
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**8.72%**	9.01%	12.92%	3.57%	3.30%	**0.380**
Median	**9.48%**	9.50%	10.91%	4.69%	2.03%	**0.230**
Max	14.88%	14.11%	43.99%	10.66%	19.18%	1.496
Min	3.43%	4.42%	5.16%	-15.06%	0.20%	0.019
StDev	2.75%	2.56%	7.70%	5.71%	3.86%	0.382

Date Source: www.morningstar.ca

The ROE analysis above shows clearly that the U.S. utilities in the U.S. sample possess greater risk than Alberta utilities. This is hardly surprising given that the U.S. sample is comprised of holding companies with various ownership structures and a variety of exposures to risks (including significant generation risks) to which Alberta transmission and distribution operating utilities are not – at least not to the same extent. The ROE analysis above supports my discussion of beta estimation in Section 3.2.4, where I provided evidence that the betas for U.S. utilities are **much higher** than those for Canadian utilities over long periods of time, and also based on beta estimates for the Canadian and U.S. samples over the 2016-21 period used in this proceeding. And as discussed in Section 3.2.4, the observed differences in beta estimates significantly understates the true difference in risk, since the estimated betas are “levered” betas (i.e., they do not adjust for differences in the leverage ratios of the companies used to estimate them). The reason this is misleading is because U.S. utilities display higher levered betas, despite the fact they should be expected to have lower leverage ratios on average (i.e., since U.S. utilities have higher allowed equity ratios). Hence, we would expect them to have lower betas than their Canadian counterparts if they had the same level of business risk. The opposite finding provides strong evidence that U.S. utilities possess *greater* business risk than Canadian utilities, since they have lower financial leverage (and hence lower financial risk) on average than Canadian utilities.

4.3.3 Conclusions About Alberta Utilities' Risk Versus Comparables

The discussion above shows that U.S. holding companies are poor comparators for regulated Alberta utilities, since they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk. Given the significant issues with using U.S. comparables, I have used only Canadian utilities in my CAPM, DCF and BYPRP analyses, while recognizing their limitations. In particular, while using Canadian utilities is better than using U.S. utilities, they are also imperfect comparators, since public information is generally only available for holding companies and not for operating companies. Given the comparability issues involved, I note that I focused on the use of current beta estimates averages, as well as long-term average Canadian utility beta estimates in arriving at a final beta estimate of 0.45. Similarly, I used averages across the utilities in my DCF analyses to try and mitigate potential comparability issues, and more importantly I use my market DCF estimates (which I consider to be more reliable) as a reasonableness check on the results.

I would note that while I do not consider U.S. utilities to be reasonable comparators, using the results from the U.S. sample would not have had any significant impact on my ROE estimates, and if anything, using them would have led me to a lower DCF estimate. For example, U.S. beta estimates ranged from 0.36 to 0.57, which are in line with my use of a beta of 0.45 (which is above the Canadian averages). My U.S. sample DCF single-stage and H-model estimates (before flotation cost adjustments) were 6.55% and 6.40% respectively, versus my corresponding Canadian sample estimates of 6.37% and 7.16% - so if I had incorporated them, it would have reduced my DCF best estimate.

The most important conclusion that arises from my analysis in Sections 4.1-4.3 is that regulated Alberta utilities possess very low business risk. My quantitative analysis in Sections 4.2 and 4.3 confirms this fact, which supports Mr. Bell's conclusions and reflects the long-standing business risk assessment of Alberta utilities by debt rating agencies.

4.4 Financial Risk and Credit Metrics

Section 4.3 shows that Alberta utilities have earned ROEs at or above their allowed ROEs for the last 17 years – exceeding them by an annual average of 0.81% (weighted average of 1.12%) over the 2005-2021 period. They have done so with very low volatility in these earned ROEs. These facts suggest that they possess low total risk, which is a function of both business risk and financial risk.

The allowed equity ratios ("**ERs**") in the 2018 GCOC Decision (which have been upheld since that time) were 37% for all of the utilities, with the exception of the ER of 39% for AltaGas. During the 2018 Proceeding, the Commission considered credit metrics, as they have in previous proceedings. In terms of thresholds for these metrics, the Commission noted in the 2018 GCOC Decision that they would follow their 2016 process, stating:[63]

> In the 2016 GCOC decision, the Commission took guidance from the EBIT coverage ratio threshold used in the 2009 GCOC proceeding, in which the Commission observed that an EBIT coverage of 2.0 was the minimum threshold associated with regulated utilities with an A-range credit rating.
>
> In the 2016 GCOC decision, the Commission also placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using a "low volatility scale." The Commission noted that the credit metric benchmarks used by S&P for an A-range credit rating are an FFO coverage ratio of 2.0 to 3.0, an FFO/debt ratio of 9.0 per cent to 13.0 per cent, and an EBITDA coverage ratio of 2.5 to 4.0. The Commission did not focus on the EBITDA coverage ratio in the 2016 GCOC decision.
>
> In the 2016 GCOC decision, the Commission also calculated the deemed equity ratios that were required to attain the minimum credit metrics necessary to maintain an A-range credit rating

[63] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 141, para. 699, 700 and 701.

> for a typical taxable distribution utility, a typical non-taxable distribution utility, a typical taxable transmission utility and a typical non-taxable transmission utility. The Commission has performed the same calculations as part of this decision.

Mr. Bell's evidence shows that all of these metrics for Alberta utilities would comfortably exceed these thresholds noted above using the existing ER of 37% and allowed ROE of 8.5%. His evidence further shows that the metrics would satisfy the requirements above if the ER was maintained at 37%, while the allowed ROE was reduced to 6.75%, and the utilities continued to earn about 1.0% above this allowed ROE (i.e., ROE = 7.75%), as they have done over the past 17 years.

Given my conclusions regarding the low risk possessed by Alberta utilities, the credit metric analysis above shows that the Commission can comfortably reduce the allowed ROE in combination with the existing equity ratio of 37%, and maintain the financial integrity of the utilities.

4.5 Capital Structure Recommendation

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility and their ability to consistently generate high profits. They have consistently generated ROEs above the allowed ROEs for the last 17 years consecutively, and these earned ROEs have displayed low volatility. As a result, I recommend that the Commission maintain existing allowed equity ratios, in combination with my recommended reduction in the allowed ROE. My risk analysis suggests this is a reasonable approach, and the credit metric analysis provided by Mr. Bell supports this position.

5 AUTOMATIC ADJUSTMENT MECHANISM (AAM) ROE FORMULA

Consistent with my previous evidence and comments on the issues, I continue to believe that an equity risk premium approach is the most appropriate formulaic approach to determining allowable ROEs. It is the general approach that is used in almost every other jurisdiction, and in fact, I would argue that it is the only viable approach. It is noteworthy that the approach used by the Ontario Energy Board ("**OEB**") for example, is a variation of two ERP models (i.e., the CAPM and the BYPRP approaches) commonly relied upon in determining the cost of equity (i.e., allowed ROE) during cost of capital hearings. In fact, it is a direct variation of the BYPRP approach that I have used in my current and previous evidence. In particular, the OEB approach integrates both the risk-free rate (or RF), as proxied by long-term government bond yields, and the A-rated utility yield spread – which together comprise the A-rated utility yield (i.e., A-rated utility yield = RF + A-rated utility yield spread). The OEB approach also utilizes one of the inputs into the CAPM in the form of RF, while the market risk premium used in the CAPM is related to the risk premium that is reflected in market-determined yield spreads.

Any attempts to use a variation of the third type of model typically used in cost of capital proceedings, DCF models, would not be appropriate. First of all, such models ignore changing market conditions. Secondly, DCF model results are heavily dependent on future growth *estimates* in earnings, dividends and cash flows – all of which are subject to substantial errors, and as such is virtually impossible to determine consensus regarding such growth rates objectively. For example, in the 2020 proceedings, the growth estimates used by experts ranged from 1.4 percent to 8.8 percent, and there has been considerable debate not only regarding the growth estimates themselves, but with respect to the best methods and data sources to use in determining such estimates. As such, it is simply not pragmatic to employ such an approach for automatic allowable ROE adjustments. In contrast, both long-term government bond yields and A-rated utility yield spreads are easily observable, non-disputable, and hence provide reliable formulaic inputs.

Consistent with my previous recommendations regarding an AAM, I would not support the use of such a mechanism over long periods of time. If implemented, subject to satisfying the trigger requirement described below, such a mechanism could be useful for establishing ROEs in the interim period between regulatory proceedings that would be required at regular intervals (ideally every three years, but **never more than five years**) to provide a more comprehensive review of existing market conditions, and also to review the allowed ERs.

In order to avoid locking in an abnormally high ROE-A-yield spread and/or providing asymmetric recommendations, as discussed in Section 6.2 of my 2020 evidence, I do not recommend an AAM be implemented until the following condition is satisfied at the time an allowed ROE is established at a GCOC Proceeding:

- The A-rated utility yield is 3.84% or higher.

The rationale for choosing 3.8% was that it was the median (and also the average) A-rated utility yield over the 2012-2019 period, which means that half of the time yields were higher than this rate, and half the time they were below it. Excluding observations over longer historical periods that had higher prevailing yields that are unlikely to rematerialize in the immediate future seems reasonable. For example, the average A-rated utility yields averaged 5.65% over the pre-crisis 2004-07 period, 5.86% during 2008-09, and 4.99% over the subsequent 2010-11 period. These averages are high, and are unlikely to be observed again in the foreseeable future as they represent periods of higher interest rates in general than during our current environment (i.e., 2004-07), and periods of well above average volatility (2008-09 and 2010-11). Since 2012, A-rated utility yields have not returned to these levels.

In my 2020 evidence, I recommended against the implementation of an ROE AAM, as did all of the utilities' experts. However, in Section 6.3 of my evidence I did propose a possible AAM approach if the Commission decided to re-introduce one.[64] The approach I recommended was based on an equity risk premium approach, and is very similar to the one used by the OEB, incorporating both changes in government yields (i.e., RF), as well as changes in A-rated utility yield spreads. The section below copied from my 2020 evidence provides the *rationale* underlying this approach:[65]

> Subject to the qualifications noted above, I believe that an appropriate AAM would incorporate both government yields (RF) and A-rated utility spreads, since it is the combination of these factors that determines utilities' cost of debt financing, as discussed in Section 2.1.2, Section 3.4 and in Section 5. This is because the cost of equity to utilities, as measured by ROE, is directly related to their cost of debt, which is a function of both factors. Incorporating both of these factors into an AAM has previously been advocated by experts representing both the utilities and interveners, and the Commission has expressed support for this approach. For example, in the 2011 GCOC Decision, the Commission stated:[66]

[64] Exhibit 24110-X0213, 2020 Evidence of Sean Cleary, page 84, line 19 – page 88, line 19.
[65] Exhibit 24110-X0213, 2020 Evidence of Sean Cleary, page 85, lines 22-27 and page 86, lines 1-13.
[66] Decision 2011-474, 2011 GCOC Decision, page 30, para 164.

> All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula.

The Commission also provided support for such an approach in the 2013 GCOC Decision, stating:[67]

> The Commission observes that all three expert witnesses recommended that, if an ROE formula was to be adopted, it should incorporate the two elements: changes in government bond yields, and changes in utility bond spreads. In Decision 2011-474, the Commission agreed that this type of a formula has advantages over the single-variable formula, as it is likely to better reflect any fluctuations in capital market conditions.

The implementation details of my recommended AAM approach in my 2020 evidence is copied below for ease of access:[68]

> I concur with the Commission's guidance in previous decisions, as I believe it is important to consider both factors that influence utilities' cost of debt. As a result, if the Commission does decide to implement an AAM, I would recommend the following mechanism at a future GCOC Proceeding when A-rated utility yields are 3.8% or higher (i.e., my criteria for using an AAM):
>
> The allowed ROE would be determined based on the following formula:
>
> ROE = ROE(base) + [0.75 × (A-yield Nov 30 – A-yield base)]
>
> Where,
>
> ROE(base) = Allowed ROE set at the last Proceeding;
>
> A-yield Nov30 = the A-rated utility yield obtained from Bloomberg as of November 30th in the year prior to which the automatic allowed ROE would apply; and,
>
> A-yield base = A-rated utility yield obtained from Bloomberg at the date at which the initial allowed ROE is set.

[67] Decision 2191-D01-2015, 2013 GCOC Decision, page 83, para 410.
[68] Exhibit 24110-X0213, 2020 Evidence of Sean Cleary, page 86, lines 14-22, and page 87, lines 1-27.

> For example, assume the allowed ROE was initially set at 7.5% (ROE(base)) at a time when the A-rated utility yield was 4% (A-yield base) – say for 2023. Since the A- rated utility yield is greater than 3.8%, the Commission could implement the AAM, assuming there are no other reasons not to do so. Assuming the Commission implemented the AAM in a 2023 GCOC Decision, with an initial allowed ROE of 7.5% for 2023. If A-rated utility yields had increased to 4.4% as of November 30, 2023, then the allowed ROE for 2024 would equal:
>
> $$\text{ROE} = 7.5 + [0.75 \times (4.4 - 4.0)] = 7.5 + 0.3 = 7.8\%$$
>
> This mechanism is an adaptation of the previous formula, which used 75% of government yield changes, that were based on government yield Consensus Forecasts. Given the evidence provided previously regarding the inaccuracy of such Consensus forecasts, it seems prudent to simply use the prevailing rates, which are likely to be more accurate predictions of future rates, and in any event represent the actual prevailing level of interest rates at the time. Secondly, using A-rated utility yields rather than simply government yields "simultaneously" incorporates the impact of both government yields and yield spreads. This is because the A-rated utility yield can be decomposed as the sum of these two components, as shown below:
>
> A-Rated utility yield = 30-year government bond yield + A-rated utility yield spread
>
> Thus, using A-rated utility yields at a particular point in time is easy to implement, and more importantly, it adequately reflects utilities' actual cost of debt, since it is a function of both government yields (i.e., interest rate levels) and yield spreads. These two factors tend to go in opposite directions, as discussed in Section 5. Using the resulting cost of debt to utilities' therefore reflects how the changes in each of these variables is offset by changes in the other variable.

I recommend the suspension of the AAM approach if A-rated utility yield spreads exceeded 2 percent, for the reasons copied below from my 2020 evidence:[69]

> I would recommend that the Commission consider reviewing, modifying or suspending the AAM if the following condition occurs while the AAM is in place:
>
> - A-rated utility yield spreads exceed 2%.

[69] Exhibit 24110-X0213, 2020 Evidence of Sean Cleary, page 88, lines 1-16.

> The existence of A-rated yield spreads greater than 2% would be indicative of a period of extreme uncertainty in Canadian capital markets. For example, over the January 2003- January 13, 2020 period, the average A-rated yield spread was 1.37%, with a maximum of 3.05% during December 2008, which was at the height of the financial crisis. However, for the most part, these spreads fluctuated but did not approach such levels again. In fact, the 95th percentile for the spread over this period was 1.94%, and 2.01 represents the 95.5th percentile, and the spread has only exceeded 2% between October 2008 and June 2009, and briefly over the January-March 2016 period. This evidence suggests that a spread exceeding 2% indicates extreme capital market uncertainty, which is the kind of conditions in which an AAM might not work as desired – as previously indicated by the Commission. While this may not warrant suspension of the AAM, at minimum, it warrants a thorough review of existing capital market conditions at that time before continuing to use the recommendations of the AAM.

For comparison purposes, I note the differences between the formula I proposed in 2020 discussed above, and the OEB approach:

1. The OEB formula uses **weights of 0.5** to scale both changes in government yields and changes in yield spreads, while the approach above uses a weighting scale of **0.75**.
2. The OEB formula uses 30-year government bond yield **"forecasts"** as opposed to the **actual prevailing yield**. I rely on the actual prevailing yield based on a significant amount of empirical evidence that exists, including evidence provided in Section 2.1.2 of my current evidence (including Figure 2 and Table 2), which provides significant and compelling empirical support that using the prevailing bond yield is **much more accurate** than relying on forecasts, which have been shown to be very unreliable. In addition to the inaccuracy of these 10-year yield forecasts, 10-year government yield forecasts are simply the starting point, then another "estimate" of the spread between 10 and 30-year yields must be applied, which is again subject estimation errors. Finally such an approach is **significantly easier to implement**, since it simply requires obtaining the observed (and easily attainable) actual 30-year government yields and the actual A-rated utility yields as of November 30th in a given year, so no "estimates" are required.

3. The OEB formula decomposes the A-rated utility yield into **two components** – government 30-year yield forecasts, and the A-rated utility spread, whereas I simply used readily observable actual A-rated utility yields (that do not need to be "estimated"), which by definition equal actual 30-year bond yields plus the actual A-rated utility yield spread.

Related to number 3 above, I note that there is no reason that my 2020 formula cannot be broken down into its two components to provide insights as to the contribution to recommended allowed ROE that result from changes in both RF and A-rated yield spreads individually. I had provided the formula with both factors combined into the A-rated utility yield for simplicity purposes in implementing the adjustment mechanism. In order to provide more information on the respective influences of changes in RF and yield spreads, I propose the following slight adjustment (*in format only – i.e., net recommendations remain unchanged*) to my 2020 recommendation:

ROE = ROE(base) + [0.75 × (GoC 30-year (Nov 30) – GoC yield (base)]

+ [0.75 × (A-yield spread (Nov 30) – A-yield spread (base)]

I revisit the implementation example I provided above for illustrative purposes:

Assume the allowed ROE was initially set at 7.5% (ROE(base)) at a time when the A-rated utility yield was 4% (A-yield base) and RF was 2.6% – say for 2023. This implies an A-rated utility yield spread of 1.40%. Since the A- rated utility yield is greater than 3.8%, and the yield spread is well below 2%, the Commission could implement the AAM, assuming there are no other reasons not to do so. Assuming the Commission implemented the AAM in a 2023 GCOC Decision, with an initial allowed ROE of 7.5% for 2023, if 30-year government yields increased to 2.9%, while A-rated utility yields increased to 4.4% as of November 30, 2023 (implying a yield spread of 1.5%), then the allowed ROE for 2024 would equal:

$$ROE = 7.5 + [0.75 \times (2.9 – 2.6)] + [0.75 \times (1.50 – 1.40)] = 7.5 + 0.225 + 0.075 = 7.8\%$$

Notice that we get the same answer as we did when we simply used the change in A-rated utility yields from 4.0 to 4.4%, which also resulted in a 0.3% increase in ROE. However, breaking it down into the two components, we can now see that 0.225% of that total change is due to an increase in government bond yields, while the other 0.075% is due to an increase in A-rated utility yields.

Finally, I do not recommend any corresponding adjustments to allowed equity ratios in conjunction with an AAM for setting allowed ROEs. Allowed equity ratios should be established at regular GCOC proceedings based on assessment of utility risk at that time.

This concludes my testimony.

Attachment 6: Newfoundland cost of capital proceedings in 2015-2016

BEFORE THE NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

EVIDENCE OF DR. SEAN CLEARY, CFA,

BMO PROFESSOR OF FINANCE

SUBMITTED ON BEHALF OF:
THE NEWFOUNDLAND CONSUMER ADVOCATE

REPORT ON CAPITAL STR UCTURE & RELATED ISSUES

February 17, 2016

TABLE OF CONTENTS

1. INTRODUCTION

1.1 Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am currently the BMO Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

Most recently, I served as an expert witness on behalf of the Utilities Consumer Advocate (UCA) of Alberta in 2014, where I prepared evidence and testified regarding appropriate risk margins for commodity risk for regulated Alberta utilities. I also served as an expert witness for the UCA of Alberta in the generic cost of capital proceedings in 2013-14, preparing evidence and testifying regarding an appropriate ROE and capital structure for regulated Alberta utilities. Prior to that, I provided a report for the Chicken Farmers of Ontario (CFO) recommending an appropriate ROE, capital structure, and cost of capital for the average chicken farmer in Ontario. This information was used in determining a new pricing formula for Ontario chickens.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, since most of my research has dealt with empirical corporate finance and capital market issues, consisting of 28 publications. My work has been cited over 2,000 times. Most of this work has dealt directly or indirectly with capital structure and cost of equity issues. I have authored or co-authored 13 finance text books, all of which deal with capital structure, cost of equity, and cost of capital analysis. The four editions of "Introduction to Corporate Finance" (co-authored with Laurence Booth, University of Toronto) include estimates of the cost of equity and cost of capital for actual companies. I estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is included in Attachment A to my evidence.

1.2 Purpose of Testimony

On page 17 of Order No. P.U. 13 (2013), the Newfoundland and Labrador Board of Commissioners of Public Utilities (hereafter the Board) stated:

> *"The Board notes that it has been some time since Newfoundland Power's capital structure has been comprehensively reviewed and that it may be appropriate for this issue to be addressed in Newfoundland Power's next general rate application."*

In response to this call for a review, the Consumer Advocate of Newfoundland and Labrador has requested that I recommend an appropriate capital structure (i.e., equity ratio) for Newfoundland Power.

1.3 Summary of Capital Structure Recommendations

The Canadian economy is forecast to grow slowly, but positively, over 2016 and 2017 as a result of low oil and commodity prices and a low Canadian dollar, which is beginning to provide anticipated benefits. The Newfoundland and Labrador economy has been hit harder than most provinces and economic growth is expected to be negative in 2015 and 2016, before returning to positive territory in 2017 and beyond. Newfoundland Power (NP) has been resilient to such economic downturns in the past, and I expect that it will be this time around.

My qualitative analysis confirms that NP continues to be a low business risk electric distribution utility operating in a very supportive regulatory environment, similar to the conclusions reached by the Board in previous decisions, and also consistent with the analyses of credit rating agencies of NP. My quantitative analysis provides strong verification of these qualitative conclusions, as NP is shown to display much lower volatility in operating income than comparable U.S. firms, and slightly below Canadian comparable utilities. As such, I conclude that NP continues to be a very low business risk firm.

My analysis in section 3.3.1 shows that NP has lower financial risk than other Canadian utilities based upon a combination of an allowable ROE which is about average and equity ratios which are much higher than average. Given this attractive ROE to equity ratio combination, it is therefore not surprising that NP has displayed superior credit metric ratios than its Canadian peers, as discussed in Section 3.3.2. An examination of credit metric sensitivity to changes in allowed ROEs and equity ratios indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and the allowable ROE was also reduced.

It is not clear why a low business risk firm like NP requires an equity ratio that is much higher than average, while being allowed to earn an ROE that is around average. I recommend that the Board reduce the equity ratio to 40%, which would bring it in line with, but still slightly above, Canadian utility averages. The additional “above average” 5-6% equity thickness is not warranted based on NP’s business risk, nor is it required to maintain solid credit metrics that will permit NP to maintain its ability to raise credit on reasonable terms.

2. ECONOMY OVERVIEW

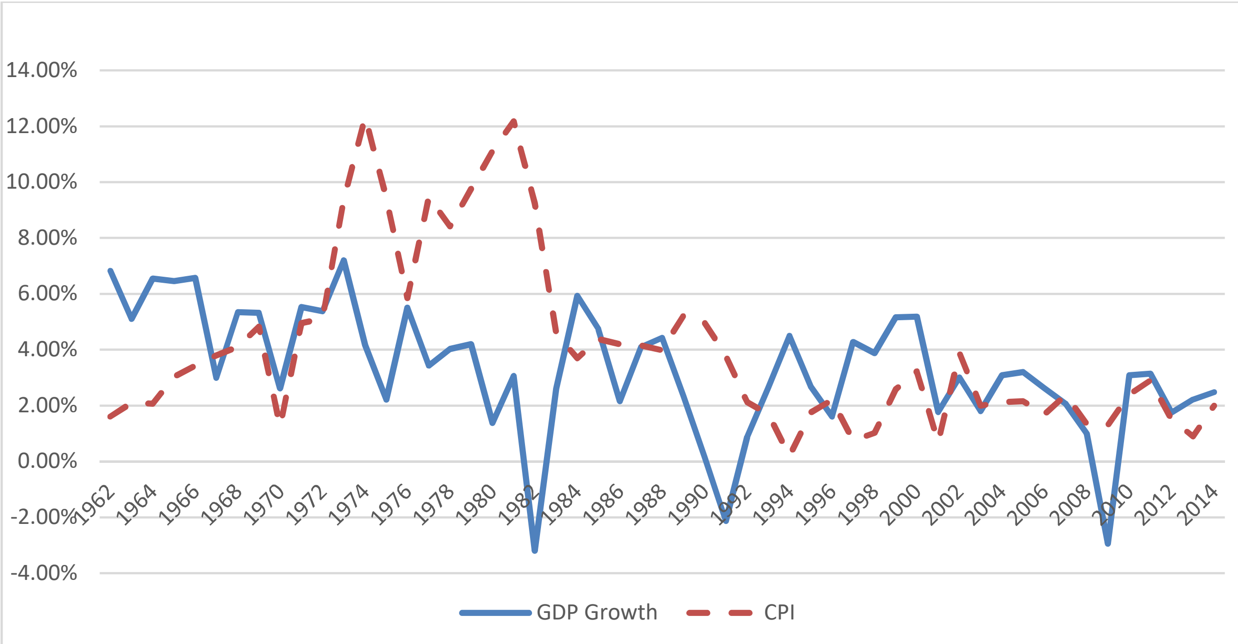
2.1 The Canadian Economy

2.1.1 Historical Evidence

The figure below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index (CPI) over the 1962 to 2014 period. The graph shows that real GDP growth has generally been in the 2 to 6 percent range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average for GDP growth over the entire period was 3.3% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.6% (median 2.7%) over the 1992 to 2014 period. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from the figure, and also as measured by the standard deviation reported in Table 1.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2014)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2014)

	1962-2014 (%)		1992-2014 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.28	4.06	2.57	1.86
Median	3.09	3.23	2.66	1.99
Max	7.20	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.24	3.13	1.68	0.86

Data Source: Statistics Canada.

Figure 1 also reports annual changes in CPI, which averaged 4.06% (median 3.23%) over the entire period. These summary stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average of 1.86% (median 1.99%). CPI growth has also been very stable during this latter period, which is obvious from the graph, and also by the huge decline in standard deviation from 3.1% to 0.9%. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2 Global Economic Activity

The global economy has faced several challenges since 2008, but is expected to grow at a moderate pace in 2016 and 2017. For example, Table 2 shows the January 2016 Consensus Economics Inc. Forecasts for average global real GDP growth figures of 2.7% and 3.0%, while the Bank of Canada's January 2016 Monetary Policy Report (MPR) estimates were slightly higher at 3.3% and 3.6%. Table 2 shows that the expected global improvements are based in large part on expectations that the U.S. economy will continue to grow steadily over 2016 and 2017 in the 2.4-2.5% range, while the Euro zone will continue to rebound back closer to normal growth levels with expected growth rates of 1.6-1.7% for 2016-17.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2016-2017)

Real GDP Growth (%)	2016		2017	
	Consensus	Bank of Canada	Consensus	Bank of Canada
World	2.7	3.3	3.0	3.6
U.S.	2.4	2.4	2.5	2.5
Euro Zone	1.7	1.6	1.7	1.6

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

The Bank of Canada notes in its January 2016 MPR that global growth will be the result of diverging prospects at the individual country level. They note that U.S. economic growth has been healthy, with consumer confidence improving, wage growth showing signs of increasing, and increases in the levels of business investment outside of commodity-related sectors. They also note that the U.S. Federal Reserve's implementation of gradual withdrawal of monetary stimulus had only a minor impact on market prices, since it was widely anticipated. The Bank suggests that, in contrast to the U.S., expected areas of economic growth in Japan and the Euro area will be driven by "accommodative monetary policy, low oil prices and past exchange rates."

At the same time, as a result of a rebalancing from manufacturing to service industries, the Bank forecasts that China's growth will stabilize at just over 6% by the end of 2017, down from just over 7% in 2014. While the Bank expects infrastructure investment to slow, it will "remain robust through 2017, in line with the Chinese government's stated priority to address ongoing infrastructure needs." They also note mixed economic growth messages in other emerging economies. While the recession in Brazil is now expected to last longer than previously expected, they forecast improvements in growth in oil-importing emerging markets such as emerging Asian countries. Finally they expect continued solid growth in India of 7-8%.

2.1.3 Today's Outlook

Of course, three of the main stories contributing to this divergence of global fortunes have been the falling price of oil, the decline in other commodity prices, and the continued strengthening of the U.S. dollar. These stories have had a similarly diverse impact on the Canadian economy. For example, the Bank shows in Chart 13 (page 17) of the January MPR that over the January 2013-October 2015 period output growth followed very different patterns for: (1) oil and gas related industries (9 percent of GDP); (2) non-energy commodity related industries (7 percent of GDP); and, (3) non-resource sector industries (84 percent of GDP). In particular, the graph shows that output grew faster in sectors (1) and (2) during 2013, but since mid-2014 the decline in oil and gas related industries has been significant, while there has been a slight decline in output for non-energy commodities. In contrast, output from other sectors of the economy have continued to grow at a steady rate.

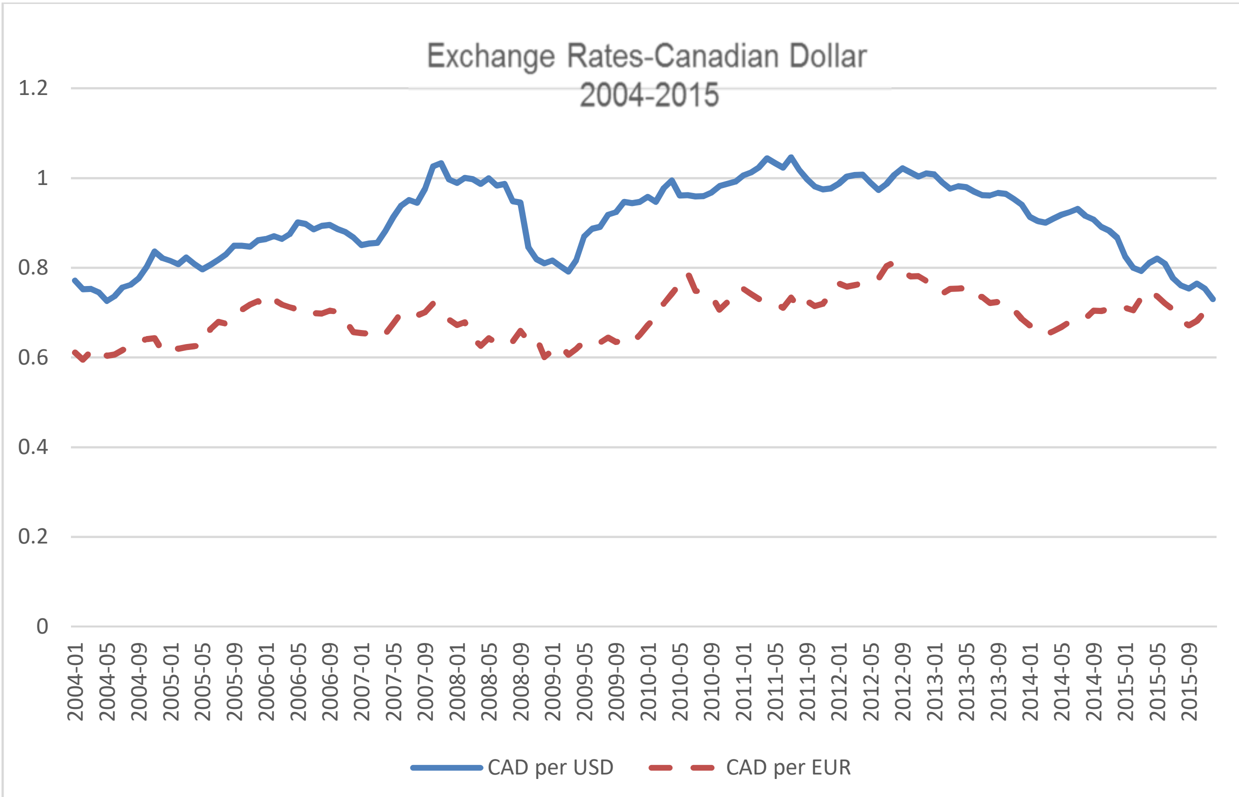
Oil prices had declined by over 70 percent of their June 2014 peak as of January 2016. While the Bank does not make forecasts for oil prices, they felt that risks were tilted to the downside in the near term based on existing inventories, climate forecasts, and geopolitical risks (which could impact prices in either direction, depending on the scenario). In contrast, the Bank feels the risks of oil price changes are tilted to the upside in the medium term, as reductions in investment in the oil industry impact supply. Interviews with energy firms in the fall of 2015 suggested that US$45 per barrel of WTI was a break-even price. Not surprisingly, oil firms cut capital spending by about 40 percent in 2015, and estimated they would reduce 2016 spending by 25 percent, if prices remained in the low US$30s. Firms have also worked at improving productivity and have reduced labour costs through layoffs and by cutting salaries and bonuses.

Reduced commodity prices have led to an appreciation in the currencies of commodity importers, and a depreciation in the currencies of commodity exporters. Figure 2 depicts the significant decline in the Canadian dollar relative to the U.S. dollar (USD) since 2013. The graph shows that the CAD traded around par during at the start of 2013, but has trended downward, sitting at around $0.73 at the end of 2015. Obviously, such a rapid and severe decline in the value of the loonie has impacted our economy, as discussed below. The expected improvement in exports due to the decline in the dollar have been slow to materialize, but are now doing so, and are expected to improve in 2016 and 2017. Finally, the Bank of Canada's easy monetary policy and the resulting accommodative financial conditions[1] have provided ongoing support to the economy.

[1] For example, in the Bank of Canada's winter Business Outlook Survey, most firms surveyed characterized credit as "easy or relatively easy to obtain."

FIGURE 2

EXCHANGE RATES – CANADIAN DOLLAR (2004-2015)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

As a result of the factors discussed above Canada's economy has experienced slower than expected GDP growth during 2015, resulting in a slight increase in the overall unemployment rate to 7.1%. Lower oil and commodity prices have depressed activity and investment in those sectors and the provinces that are most heavily reliant upon those sectors (i.e., Alberta, Newfoundland and Saskatchewan). In contrast, the Bank predicts that non-commodity export industries that are sensitive to the exchange rate will outperform, which will lead to an increase in non-resource based business investment.

Combining all of these varied effects is never easy, but the Bank predicts that the Canadian economy will continue its adjustment to lower oil and commodity prices, with the worst of these adjustments being behind us. The Bank predicts, at the aggregate level, that household expenditures will expand moderately, and that real GDP growth will improve from 0.3% during 2015 to 1.9% in 2016 and 2.5% in 2017. Table 3 shows that the 2016 and 2017 forecasts are in line with, but slightly higher than the Consensus forecasts (1.7% and 2.2%), and with those of the IMF (1.7% and 2.4%) and the OECD (2.0% and 2.3%).

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2016-2017)

Conf. Board of Canada	1.8	2.3
CIBC World Markets	1.7	2.3
IHS Economics	1.6	2
Citigroup	1.7	2.1
BMO Capital Markets	1.6	2.2
Desjardins	1.7	2.2
Econ Intell Unit	1.8	2.1
EconoMap	1.6	2.3
Oxford Economics	1.7	2.2
JP Morgan	1.5	2.2
National Bank	1.6	1.7
RBC	1.8	2.6
TD Bank	1.6	1.8
University of Toronto	1.8	3
Scotia Econ	1.6	2.3
Informetrica	2.2	2.1
Average	**1.7**	**2.2**
Median	**1.7**	**2.2**
Max	**2.2**	**3**
Min	**1.5**	**1.7**
IMF (Oct 15)	**1.7**	**2.4**
OECD (Nov 15)	**2**	**2.3**
Bank of Canada (Jan 2016)	**1.9**	**2.5**

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

Based on the discussion above, the Bank predicts that excess capacity will diminish, and that inflation will remain at 1.4% in 2015 and 2016, before increasing to 1.9%, close to its target rate in 2017. Their corresponding core inflation estimates for 2015-17 were 2.0, 2.0 and 2.0 respectively. The Bank's total inflation projections were below, but in line with the Consensus forecasts, as well as with those of the IMF and OECD, all of which can also be found in Table 4.

TABLE 4

CPI FORECASTS – CANADA (2016-2017)

Source: Consensus Economics Inc. (January 2016) and Bank of Canada MPR (January 2016).

CPI Forecast	2016	2017
Conf. Board of Canada	1.6	2
CIBC World Markets	2	2.3
IHS Economics	2.1	2
Citigroup	1.8	2
BMO Capital Markets	1.7	1.9
Desjardins	1.5	2
Econ Intell Unit	1.8	2.2
EconoMap	1.6	2
Oxford Economics	1.6	1.9
JP Morgan	1.6	2
National Bank	1.7	1.6
RBC	2	1.8
TD Bank	1.5	1.9
University of Toronto	1.8	2.2
Scotia Econ	1.8	2.2
Informetrica	2.1	2
Average	**1.8**	**2**
Median	**1.85**	**2**
Max	**2.1**	**2.3**
Min	**1.5**	**1.6**
IMF (Oct 15)	**1.6**	**2.3**
OECD (Nov 15)	**2**	**2.3**
Bank of Canada (Jan 2016)	**1.4**	**1.9**

Of course, there are several uncertainties associated with the projections above. The Bank noted the following key risks to their inflation outlook, and suggested that these risks are “roughly balanced over the projection period”: (1) lower potential output; (2) greater exchange rate pass-through; (3) lower oil prices and threshold effects; and, (4) slower growth in emerging-market economies (EMEs).

The Bank acknowledges it is challenging to estimate the timing and impact of labour and capital allocations to non-commodity sectors. They suggest that they have focused on the low end of output and growth rates, and that the actual output gap could turn out to be below their estimates (i.e., if they were too conservative).

As a result, they suggest that potential output represents a potential positive for economic growth, and hence a corresponding upside risk to inflation.

The Bank's estimate of the impact of past CAD depreciation of 0.7 percentage points to 2016 inflation may be on the low side, based on historical experience. Hence, if exchange rate pass-through exceeds this estimate, both economic growth and inflation will be higher, and the Bank judges this to be an upside risk to inflation.

If existing or future oil prices remain low or decline further, they may be below threshold levels for some oil firms to cover ongoing operating costs, which could further impact investment and employment in the industry. This would impact employment, as well as general confidence, and as such would represent a potential drag on economic growth, and hence a downside risk to inflation.

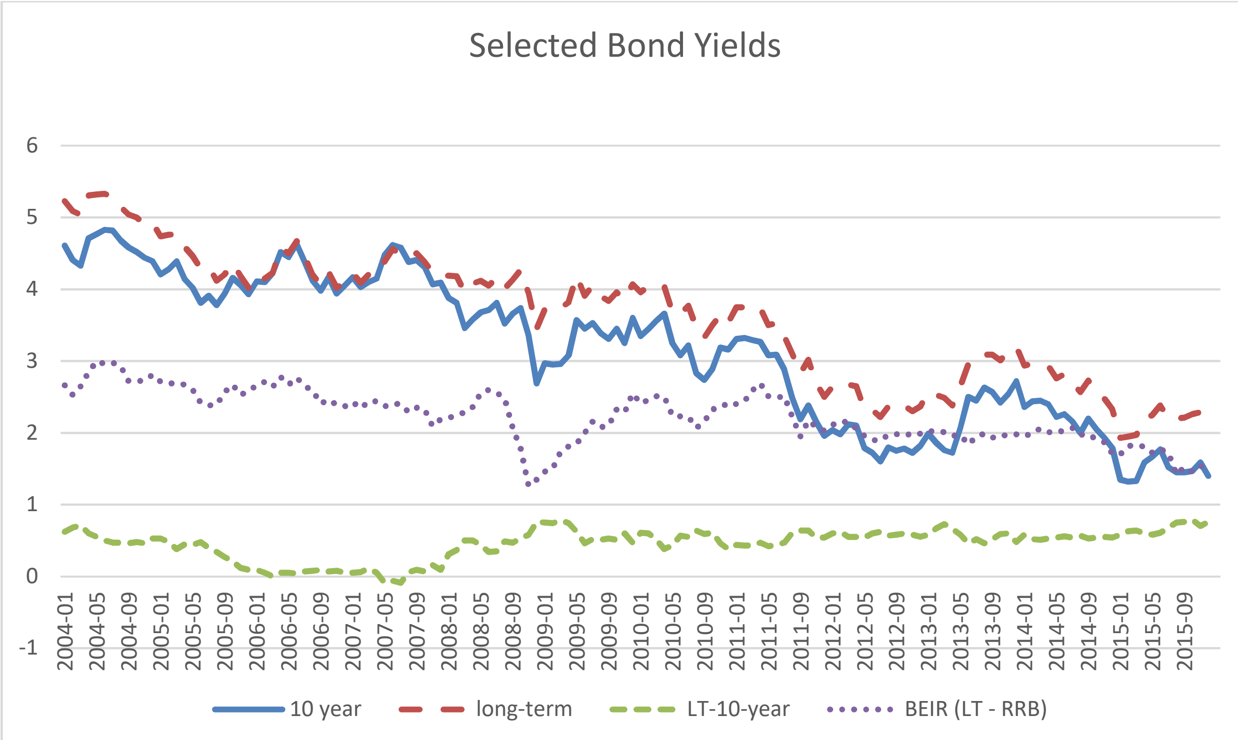
Weaker EME growth (e.g., China, Brazil, etc.) could be caused by several factors. If EME growth lags expectations, this could lead to reduced exports by the U.S., lower commodity prices, and/or increased market uncertainty. All of these outcomes would adversely affect Canada's economic growth prospects, and hence represent a downside risk to inflation.

2.1.4 Interest Rate Levels

In light of recent levels of GDP growth and CPI, as well as their forecasted values in the immediate future, it is not surprising that interest rates in Canada have remained low over the most recent time period. Figure 3 shows 10-year and long-term bond yields in Canada over the last 12 years, which have moved in tandem for the most part, with a correlation coefficient of 0.98 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.46% (0.52%) over the entire period. It is obvious from the graph that this spread increased during the last half of 2015 and sat at 0.76% at the end of 2015, with long-term rates of 2.16% and 10-year rates of 1.40%. The graph also shows the break-even inflation rate (BEIR), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR can be viewed as an indicator of future inflation rates. This rate remained within the Bank's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.26% in November of 2008 around the peak of the crisis, and averaging 2.2% overall, slightly above the Bank's target. It sat at 1.49% at the end of 2015, a mere 9 basis points above the Bank's CPI forecast for 2016, and 21 basis points below the Consensus CPI forecast.

FIGURE 3

SELECTED BOND YIELDS – CANADA (2004-2015)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Considering the discussion above, it is reasonable to assume that bond yields will increase, albeit slowly, in the coming months. This seems to be the consensus view of most economists in January of 2016, as can be seen in Table 5. The January 2016 Consensus Forecasts for 10-year Canada bond yields were 1.7% for the end of April 2016 and 2.1% for the end of January 2017 – up from the 2015 year-end value of 1.4%. If we assume the increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 1.75% for 2016, with a rate of 2.1% at the start of 2017. Assuming that the long-term average 50 basis point spread of 30-year yields over 10-year yields persists throughout 2016 and 2017, this implies long-term rates would increase from their 2015 year-end level of 2.16% for an average of 2.25% throughout 2016, and would lie at around 2.6% by January of 2017. The forecast averages for 3-month T-bill yields, which are not included in the table, were 0.5% for April 2016 and 0.7% for January 2017, little changed from current levels.

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2016-17)

10-Year Canada Yields	***Apr-16***	**Jan-17**
Conf. Board of Canada	*1.6*	2
CIBC World Markets	*1.6*	2.1
IHS Economics	*2.1*	2.3
Citigroup	*1.7*	1.8
BMO Capital Markets	*1.5*	1.7
Desjardins	*1.5*	1.9
Econ Intell Unit	*NA*	NA
Oxford Economics	*1.6*	1.8
EconoMap	*1.5*	1.7
JP Morgan	*NA*	NA
National Bank	*1.8*	2
RBC	*1.7*	2.4
TD Bank	*1.8*	2.1
University of Toronto	*1.6*	2.7
Scotia Bank	*1.5*	1.8
Informetrica	*1.8*	2.5
Average	**1.7**	**2.1**
Median	**1.6**	**2**
Max	**2.1**	**2.4**
Min	**1.5**	**1.7**

Source: Consensus Economics Inc. (January 2016).

2.2 The Newfoundland and Labrador Economy

Unfortunately, Newfoundland and Labrador (NL) is one of the provinces affected negatively by the recent decline in oil and commodity prices. The negative outlook is obvious from Table 6, which provides forecasts of real GDP growth for NL for 2015 and 2016. The private sector average forecasts (which includes the big five banks and the Conference Board of Canada) are for -2.2% real GDP growth in 2015 (with a maximum of -0.2% and a minimum of -3.5%), and -0.7 percent in 2016 (with a maximum of +0.3% and a minimum of -2.0%). The Department of Finance forecasts a decline of only 0.3 percent in 2015, followed by a decline of 1.6 percent in 2016. So there is general agreement that the economic growth will be slow for NL in the short term.

TABLE 6

NEWFOUNDLAND AND LABRADOR REAL GDP GROWTH FORECASTS (%) - 2015-16

		2015	2016
CIBC World Markets	24-Sep	-1.5	-1.0
Scotiabank Group	5-Jan	-2.7	0.2
TD Economics	8-Oct	-3.5	-0.9
BMO Nesbitt Burns	8-Jan	-1.7	-2.0
Conference Board of Canada	2-Nov	-0.2	-0.8
Royal Bank of Canada	8-Dec	-3.5	0.3
Private Sector Average		**-2.2**	**-0.7**
Department of Finance	19-Oct	**-0.3**	**-1.6**

Forecasts as of January 11, 2016

Source: http://www.economics.gov.nl.ca/frcstGDP.asp, February 6, 2015.

As the Conference Board of Canada (CB) notes in its fall provincial outlook, the NL economy has been hit by a number of factors: major projects passing their peak investment levels; mature offshore oil fields producing less oil; low oil prices; and, low commodity prices. Combined with a weak outlook for oil and commodity prices, the CB expects production and investment levels to continue to be weak.

The CB expects that oil production will remain flat over the next two years, and that oil prices will bounce back in the later part of 2016 and through 2017-18. In contrast, they expect commodity prices to remain low throughout 2016-18. This will lead to slightly negative metal production over the next two years, when combined with project life-cycle factors (e.g., iron ore production at Elross Lake and Labrador Trough peaking this year and declining going forward). One positive factor in metal production, is nickel production as Vale's Voisey's Bay mine enters phase two. This will have a positive impact on manufacturing. Combining this with the expected positive impact of a strong U.S. economy and a weak Canadian dollar, leads the CB to conclude that manufacturing will remain one of the bright spots for the NL economy in 2016-17.

The CB predicts that while business investment levels will remain higher than they were a few years ago, they will decline from their peak of over $8 billion in 2014, and lie around $6 billion in 2016 and 2017, before leveling off at just above $5 billion during 2018-20. While work continues on Muskrat Falls and Hebron oil developments, other projects have been delayed such as the West White Rose extension project, and the Alderon Iron Ore mine projects associated with transmission and development.

Residential real estate investment will be hampered by slow economic growth and weaknesses in the labour market, and will also decline.

All of these factors have led to an overall weakened economy and labour market at the start of 2016. Table 7 shows that the CB forecasts that this will lead to real GDP growth declining by -0.8% in 2016, with the unemployment rate peaking at 13.1% over the 2015-20 period. This 2016 GDP growth estimate is slightly below the average estimate of the big five banks provided in Table 6, which is -0.68%. The CB estimates that recovery will occur during the latter part of 2016, and that real GDP growth will be slightly positive (at +0.2%) in 2017, with the unemployment rate declining to 12.4%. Beyond 2017, the CB predicts that the unemployment rate will fall below 12% and decline steadily to around 11% by 2020 on the back of 2018-20 real GDP growth rates of +1.4%, +7.0% and -1.6% respectively. Finally, it is interesting to note that the CB expects the contribution to NL GDP from the utilities sector to remain positive in 2016-17 (+0.4% and +0.6% respectively), and also in the ensuing three years (+0.8%, +1.3%, and +5.9% respectively). This is consistent with the low risk nature of utilities such as Newfoundland Power, whose demand is less cyclical than most industries.

TABLE 7

CONFERENCE BOARD OF CANADA ECONOMIC FORECASTS FOR NL - 2015-2020

	NEWFOUNDLAND AND LABRADOR FORECASTS					
Growth (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Real GDP	-0.2	-0.8	0.2	1.4	9.2	0.4
CPI	0.7	4.6	2.2	2.1	2.3	2
Household Disposable Income	4.1	1.7	2.1	2.7	2.6	1.6
Employment	-0.9	-0.6	-0.4	-0.5	0.1	-0.9
Unemployment Rate	12.7	13.1	12.4	11.9	11.4	11.1
Utilities Sector GDP Contribution	9.9	0.4	0.6	0.8	1.3	5.9

3. CAPITAL STRUCTURE CONSIDERATIONS

3.1 Background

As previously noted, on page 17 of Order No. P.U. 13 (2013), the Newfoundland and Labrador Board of Commissioners of Public Utilities (hereafter the Board) stated:

> *"The Board notes that it has been some time since Newfoundland Power's capital structure has been comprehensively reviewed and that it may be appropriate for this issue to be addressed in Newfoundland Power's next general rate application."*

I begin my discussion with a review of the risk assessment of Newfoundland Power (NP) in previous hearings. In Order No. P.U. 19 (2003), the Board stated (on page 33) that they did "not anticipate a change in the business risk of NP in the foreseeable future and concurs with the assessment of NP and the cost of capital experts that NP is of average business risk compared to other utilities." On page 30, the Board noted that NP stated "All experts agreed that Newfoundland Power has an approximately average utility risk." The Order also notes (on page 32) an October 2002 report by S&P confirming an "A" rating for NP's first mortgage bonds, wherein S&P noted:

> *"Newfoundland Power's relatively low risk profile is supported by cost of service/rate of return regulation; the ability to flow through all power costs; a weather normalization mechanism; and no exposure to cyclical industrial consumers, which are serviced directly by the provincial government-owned utility, Newfoundland and Labrador Hydro."*

Recent debt rating reports (as provided in Exhibit 4 of NP's evidence) suggest that DBRS and Moody's continue to share S&P's 2002 opinion that NP possesses low business risk.

In similar fashion, the Board concluded that NP continued to be an average risk Canadian utility on page 13 of Order No. P.U. 43 (2009). On page 12 of this 2009 Order the Board noted that:

> *"The evidence shows that Newfoundland Power operates in a low risk environment. It is accepted that the regulatory regime is supportive with a range of mechanisms in place to mitigate risk…"*

The Board also noted on page 12 that Mr. Cicchetti suggested NP "operates in a low risk market under supportive regulation," and that he had characterized the regulatory regime under which NP operates as "exceptional."

Once again, on page 17 of Order No. P.U. 13 (2013), the Board suggested that at that time, they considered that "Newfoundland Power continues to be an average risk Canadian utility." The Board noted on page 14 of this Order that "Newfoundland Power argues that it continues to be an average risk Canadian utility," while the Consumer Advocate argued that NP was "at most, of average business risk and lower financial risk compared to other Canadian utilities."

The last quote in the paragraph above refers to both business and financial risk, where business risk includes an assessment of regulatory risk. The combination of business risk and financial risk determines a firm's total risk. This point is commonly accepted by expert witnesses, regulators, and by the debt rating agencies which make their overall risk (and rating) assessment by giving significant weight to both business and financial risk. In similar fashion, I will consider business risk, including regulatory considerations, then financial risk, and then discuss resulting conclusions regarding NP's capital structure.

3.2 Business Risk

The Board noted on page 11 of Order No. P.U. 43 (2009) the following summary of NP's risk position according to the Consumer Advocate (Transcript, October 14, 2009, page 25/11-20):

> *"Newfoundland Power has been and will continue to be a very well protected, stable, predictable, conservative, low risk utility operating in a very supportive regulatory environment where the company enjoys moderate, yet fairly steady customer growth, free from significant competition. With only a small amount of generation, Newfoundland Power is predominantly poles and wires. In essence, it is very low risk."*

This is an excellent summary of NP's operating environment and its resulting business risk, and is consistent with the views expressed by debt rating agencies. Hence, it seems reasonable to consider that NP continues to possess low business risk (which is consistent with the views of the debt rating agencies), unless compelling and material evidence demonstrates that NP's operating or regulatory environment has changed materially since 2013, or as far back as 2003 for that matter. My analysis below leads to me to conclude that such material changes have not taken place. Further, I provide empirical evidence which confirms *quantitatively* **-** what has generally always been agreed upon by NP, expert witnesses, and the Board, based on extensive *qualitative* analysis – NP is a low business risk utility.

3.2.1 Regulatory Risk

Newfoundland Power operates in an extremely supportive regulatory environment, which represents a big strength in terms of minimizing its business risk. This is reflected in evidence provided in previous decisions, and by the evidence provided by Mr. Coyne, who rates the Newfoundland regulatory environment among the top four in Canada. This point is also front and centre in credit rating reports for NP, both past and present. For example, the August 21, 2015 DBRS Rating Report lists a "stable and supportive regulatory environment" as the #1 strength among its "Rating Considerations." DBRS notes the effectiveness of the following mechanisms that are in place to smooth out the effects of various expenses and events: weather normalization reserve (WNR); rate stabilization account (RSA); demand management incentive account (DMIA); and, the pension expense variance deferral account (PEVDA). They conclude that NP operates in a regulatory framework that "allows Newfoundland Power to recover all prudently spent operating expenses and earn a reasonable return." I will verify the validity of this statement quantitatively later in my evidence.

In its January 19, 2015 Credit Opinion Moody's echoed the sentiment of DBRS, citing a "supportive regulatory and business environment" as one of three "Rating Drivers." In support of their conclusion, Moody's notes the pass through mechanisms mentioned by DBRS above and also notes that they consider the Public Utility Board (PUB) to be "supportive with a track record of reasonably timely and balanced decisions that enable NPI to generate stable cash flow and earn its allowed ROE and are not directly subject to political considerations." They also note that the "PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis." Once again, I will provide empirical evidence later in this report to support the validity of these statements regarding NP's cash flow stability and their consistency in earning profits.[2]

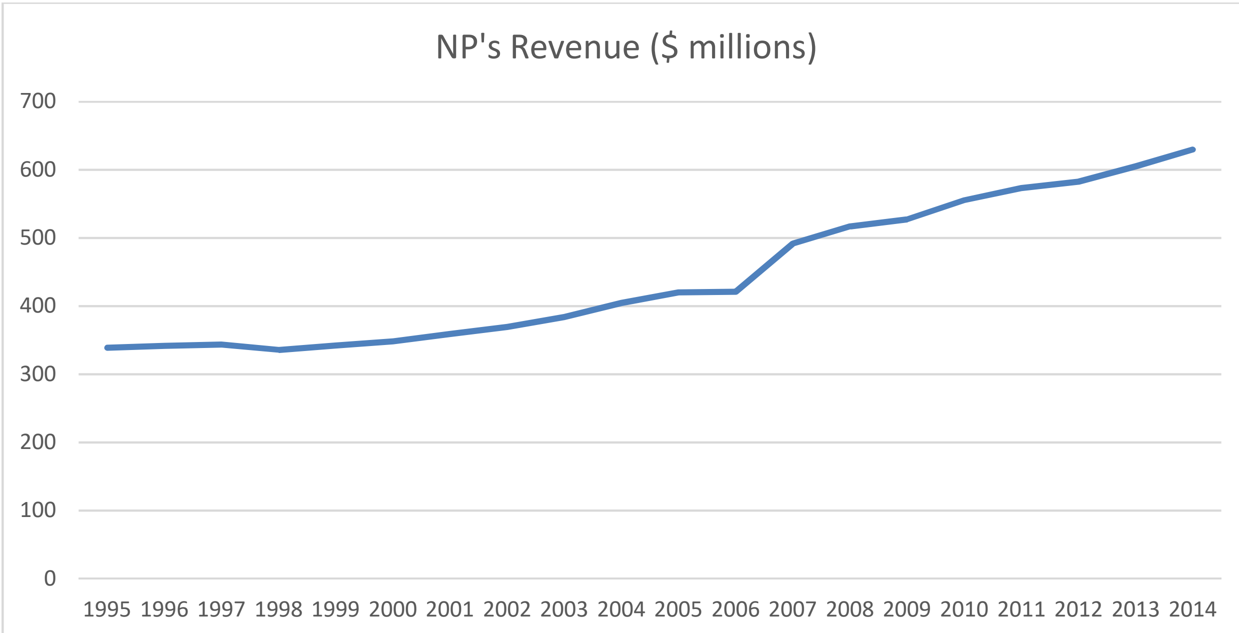
3.2.2 Operating Environment

NP operates a virtual monopoly in a low business risk environment. As a result, revenue growth has been slow but steady, as one would expect for a company operating in a mature market with virtually no competition. Figure 4 verifies this steady growth in NP's revenue for the years 1995-2014. Annual revenue growth averaged 3.38% over this period, and growth was only negative in one year, 1998, when revenue declined 2.31%.

[2] For example, Table 1 in the response to information request CA-NP-019 shows that NP has earned an ROE above the allowed ROE in 19 straight years, averaging 49.5 basis points above the allowed ROE.

FIGURE 4

NP REVENUE (1995-2014)



* Data Source: Newfoundland Power's annual reports, 1996 to 2014.

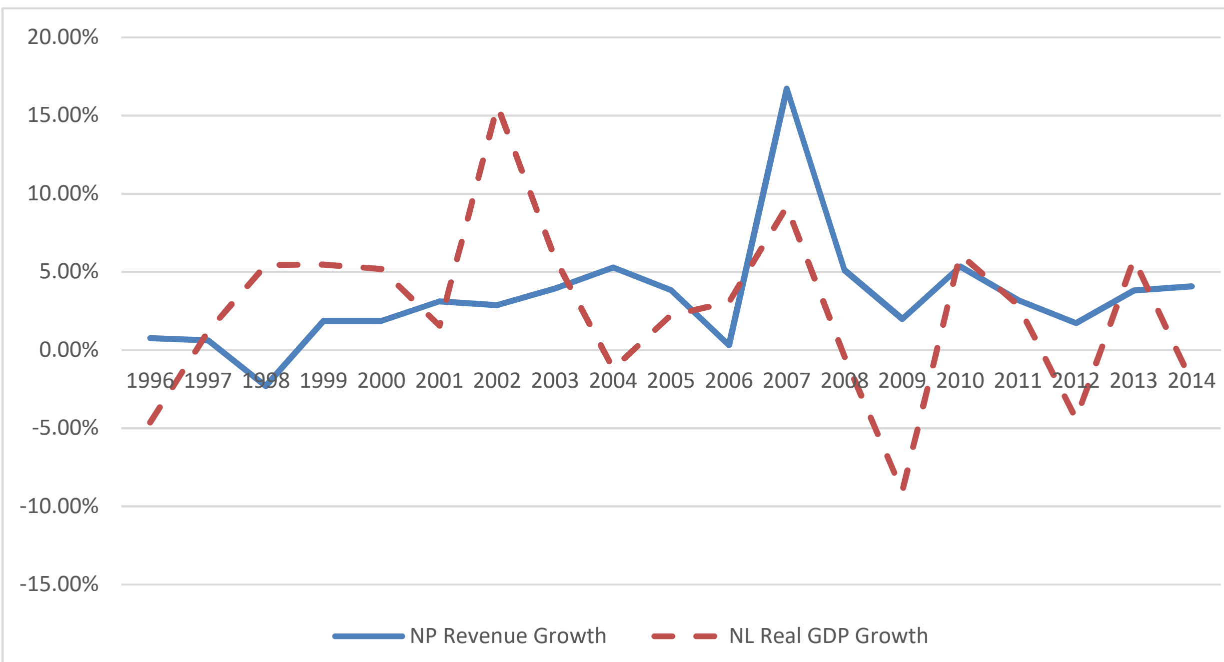
Certainly the economic forecast for Newfoundland and Labrador is not encouraging for the next two to three years. For example, as noted in Section 2, the Conference Board of Canada has forecasted negative Real GDP growth of -0.8% in 2016, followed by a slight rebound to +0.2% in 2017 and to +1.4% in 2018. However, NP has survived previous declines in economic activity and their sales and operating income continued to grow steadily. While the forecast economic decline is not a positive development, fortunately for NP it is less affected than companies operating in cyclical industries such as real estate or consumer durables. Further, given its low-risk business model accompanied with strong regulatory support, there is no obvious reason that a weak economy represents a significant increase in permanent business risk for NP. Indeed, the historical record confirms that NP has weathered previous economic "storms" and managed to maintain growth in sales and operating income, and earn ROEs at or above the allowed ROEs. For example, Figure 5 plots the annual growth rate in NP revenue versus the real GDP growth rate for Newfoundland and Labrador over the same period. As noted previously, NP experienced only one decline in revenue growth over this period, and grew in all six of the years when the real GDP growth rate was negative.

Over this period, the average annual growth rate in NP's sales was 3.4%, versus 2.5% for real GDP growth, but the volatility of NP's sales growth was much lower, as measured by its standard deviation of 2.9% versus 5.6% for NL's real GDP growth. Further, the correlation coefficient between NP's sales growth rates and real GDP growth rates over this period was positive as expected, but low at 0.27 - reflecting the fact that NP's sales are more resilient than NL's real GDP growth rates. In other words, while the Newfoundland and Labrador economic forecast is not a positive, the evidence suggests that NP can be expected to weather this economic decline, just as it has in the past.

FIGURE 5

NP REVENUE ANNUAL GROWTH VERSUS

NL REAL GDP GROWTH (%) - 1995-2014



* Data Source: Newfoundland Power's annual reports, 1996 to 2014, and CANSIM database.

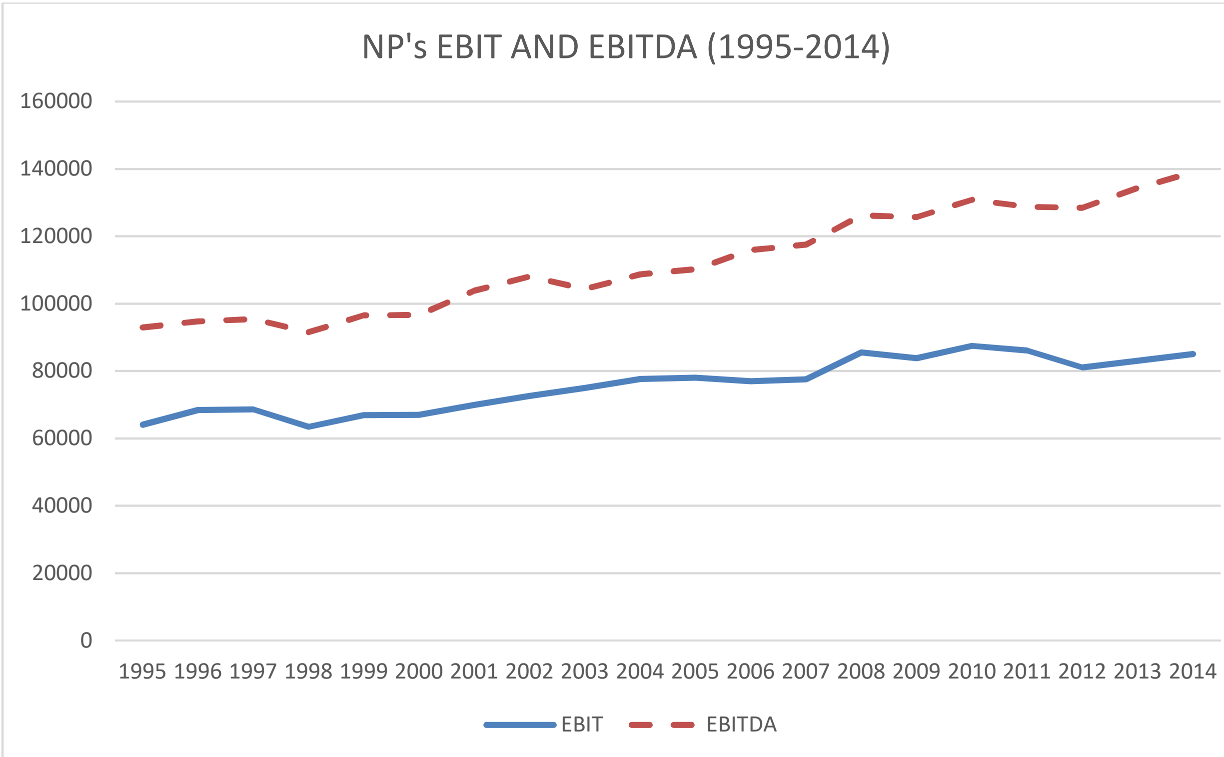
NP serves as a low-risk distributor, with almost all of their energy generation needs provided by Newfoundland and Labrador Hydro (NLH). As mentioned above, since capital expenditures and long-term debt issues are reviewed and approved by the PUB, the risk of cost disallowances is very low. The RSA, WNR, DMIA and PEVDA all serve to minimize variance in operating income related to supply costs, the impact of abnormal weather conditions, as well as other costs to NP. Hence NP faces very little risk that it will not be able to pass legitimate expenses on to customers and earn an adequate rate of return in such a supportive regulatory and business framework.

The points above are consistent with the beliefs expressed in previous hearings and with those expressed by rating agencies. For example, in its January 19, 2015 Credit Opinion, Moody's notes NP's "low-risk business model" as the # 1 rating consideration. Moody's notes that NP is "effectively protected from potential competition," and that sales have grown "at a relatively low and predictable rate of 1-2% annually," and that "growth has not taxed NPI either operationally or financially due to the relatively timely recovery of capital and operating costs." In other words, NP has low business risk because it is operating a virtual monopoly with revenue growing slowly but steadily where it is able to pass reasonably incurred costs onto consumers due to various pass through mechanisms.

It is not surprising that when we combine all of these factors with the stable growth in revenue documented previously, that we also find that NP displayed slow but steady growth in operating income over the 1995-2014 period as proxied by either EBIT or EBITDA, with EBIT (EBITDA) growing at an average annual rate of 2.2% (1.6%). The steady growth of EBIT and EBITDA displayed in Figure 6 is similar to that portrayed for revenue in Figure 4. All of the empirical observations evident in Figures 4 to 6 are consistent with a company that has low business risk. Not surprisingly, NP has been able to earn its allowed ROE or higher for 19 consecutive years.

FIGURE 6

NP'S EBIT AND EBITDA (1995-2014)



* Data Source: Newfoundland Power's annual reports, 1996 to 2014.

3.2.3 Other Considerations Raised by Mr. Coyne

On page 15 of Appendix A: Capital Structure of his evidence, Mr. Coyne states that the Muskrat Falls supply system will lead to increased "potential weather-related risk to Newfoundland Power's electricity supply." As noted in CA-NP-175, this contradicts assertions made by NLH in response to CA-NLH-115 (for the Board's Outage Inquiry) where it states that "the reliability of supply to customers will be improved." Mr. Coyne acknowledges in his response to CA-NP-175 that there is no evidence to support his claim in Appendix A, since the matter is currently being studied. As a result, there appears to be no concrete evidence to suggest that Muskrat Falls has led to an increase (or decrease) in NP's business risk.

While I do not claim to be an expert on weather patterns, I have not read any compelling evidence that suggests severe weather events are more likely to occur in 2016-17 than they have in the past. It is also difficult to see why this creates so much additional business risk for NP than it does for other Canadian utilities who are also subject to similar risks. Similarly, many U.S. utilities operate in environments where severe hurricanes and/or flooding are as likely to occur as are extreme weather events in Newfoundland

and Labrador. Of course, we all hope that such events will not happen, but they have occurred in the past, and given the supportive mechanisms in place and the support of the PUB, NP has always managed to maintain their profitability. In light of this lack of supporting evidence, I disagree with the notion that such events lead to higher business risk for NP.

Finally, Mr. Coyne suggests that NP faces greater business risk because of its size. First of all, NP has always been small relative to some, but not all, other utilities, so this does not seem to warrant attention as something that has changed since the last hearings to affect NP's business risk. Secondly, NP operates in a mature segmented market with virtually no competition and with a proven business and regulatory model that allows it to steadily grow its revenue base and pass through its costs to maintain earnings and cash flow stability. In other words, there is no reason to believe that a small firm operating a virtual monopoly in such a supportive environment is any riskier than a big firm operating in markets where there is more competition, or where they face greater regulatory risk, for example. Finally, there is no evidence that its small size has hindered NP from accessing public (or private) debt markets, as attested to by its successful long-term bond issue in 2015, and its existing short-term credit facility that is available to it.

In summary, none of the concerns expressed by Mr. Coyne in this sub-section affect my previous conclusion that NP has low business risk, which is consistent with the views expressed by rating agencies.

3.2.4 A Quantitative Assessment of NP's Business Risk

My examination of NP's operating and regulatory environment above suggests that NP possesses low business risk. The same can likely be said for most other regulated utilities, especially those that are distributors and that operate virtual monopolies in supportive regulatory environments. Certainly, it is easy to see that regulated utilities such as NP have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great an ability to pass through increases in their costs to their customers. As noted in Section 3.2.1 there has been general agreement in previous hearings that NP is an average risk regulated Canadian utility. Finally, rating reports consistently suggest that NP and most other regulated Canadian utilities have low business risk.

Most experts assessing "business risk" would agree that it refers to some variation of factors that cause uncertainty, or volatility, in operating income. For example, the 2013 CFA curriculum (Reading 38, page 82) states: "**Business risk** is the risk associated with operating earnings. Operating earnings are risky because total revenues are risky, as are the costs of producing revenues."

In this section, I use three variations of a commonly used measure of operating income volatility, the coefficient of variation of EBIT (hereafter CV-EBIT), to *quantify* a firm's level of business risk. The CV is determined by dividing the standard deviation (SD) of EBIT by the expected or average EBIT level. The rationale for using the CV as a measure of EBIT volatility rather than simply using the SD of EBIT, is that the SD is affected by the size of EBIT. In other words, firms with larger EBITs will have higher SDs of EBIT, even if they have less volatility, simply because the level of the EBIT figures used to determine the SD are much higher. The CV is more appropriate in such instances and is commonly used to measure volatility since it effectively "scales" the SD of EBIT when it is divided by the expected or average level of EBIT.

I use the three variations of CV-EBIT described below:

(1) **CV(EBIT)** is calculated as the standard deviation of EBIT for a given utility over my sample period (1995-2014) divided by the expected EBIT next year (which is determined by multiplying the most recent EBIT figure times one plus the median growth rate in EBIT for that firm).

(2) **CV(EBIT)-5 year** is calculated as the average of 5-year "rolling" estimates of CV(EBIT) using the standard deviation of EBIT over the previous five years divided by the average EBIT over the previous five years. I then take the average of these five-year CV(EBIT) estimates for each firm.

(3) **CV (EBIT/Sales)** is calculated as the standard deviation of the EBIT/Sales ratio (1995-2014) divided by the average of the EBIT/Sales ratio over this period.

Measure (1) uses expected EBIT as the denominator in determining the CV of EBIT, which is one common approach used to estimate CV-EBIT, as in Petty et al (2011) for example.[3] Notice that this approach estimates the standard deviation using all available EBIT observations. Measure (2) is another commonly used approach which uses the average EBIT as the denominator, as in the 2013 CFA curriculum (Reading 28, page 351). However, as discussed previously EBIT has continued to grow steadily for NP and also for the other utilities I use for comparison purposes. This implies that using a long-term average that will by nature be well below current EBIT levels may be inappropriate. I adjust for this by estimating the CV-EBIT using data for every year with available data using the most recent five year period. I then take the average of these rolling annual CV(EBIT) estimates for each company. Finally, measure (3) uses the EBIT/Sales

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[3] Source: Financial Management: Principles and Applications, 6th edition, by J. William Petty, Sheridan Titman, Arthur J. Keown, Peter Martin, John D. Martin, Michael Burrow, Hoa Nguyen, 2011, Pearson Higher Education.

ratio rather than the level of EBIT. This is a valid measure of business risk, since it measures volatility in the operating profit margins for firms. It also has the advantage that, as a ratio, the expected value and past average values will often coincide since these profitability margins often tend to gravitate to some long-term average. This makes it unnecessary to make the adjustments required to determine the CV-EBIT estimates as in (1) or (2) above.

Figure 7 depicts a summary of the main results of this analysis. The evidence clearly shows that U.S. utilities have much higher volatility in EBIT according to all three measures of CV-EBIT, relative to the Canadian comparable group, and relative to NP. We also see NP displays much lower business risk than the U.S. firms, and also slightly lower business risk than its Canadian peers. This leads to the conclusion that NP is very low business risk – confirming empirically, the conclusions made above in my qualitative assessment of NP's business risk. The EBIT/Sales chart in Figure 7 demonstrates that the average and median EBIT/Sales ratios are similar for the U.S. firms, the Canadian group, and NP. So, in essence, Canadian utilities, including NP, generate similar operating profit margins to U.S. utilities, but with much, much less volatility in operating income. This of course, suggests U.S. utilities have much higher business risk, which has often been argued in previous Canadian hearings.

FIGURE 7

COEFFICIENT OF VARIATION OF EBIT ESTIMATES (1995-2014)

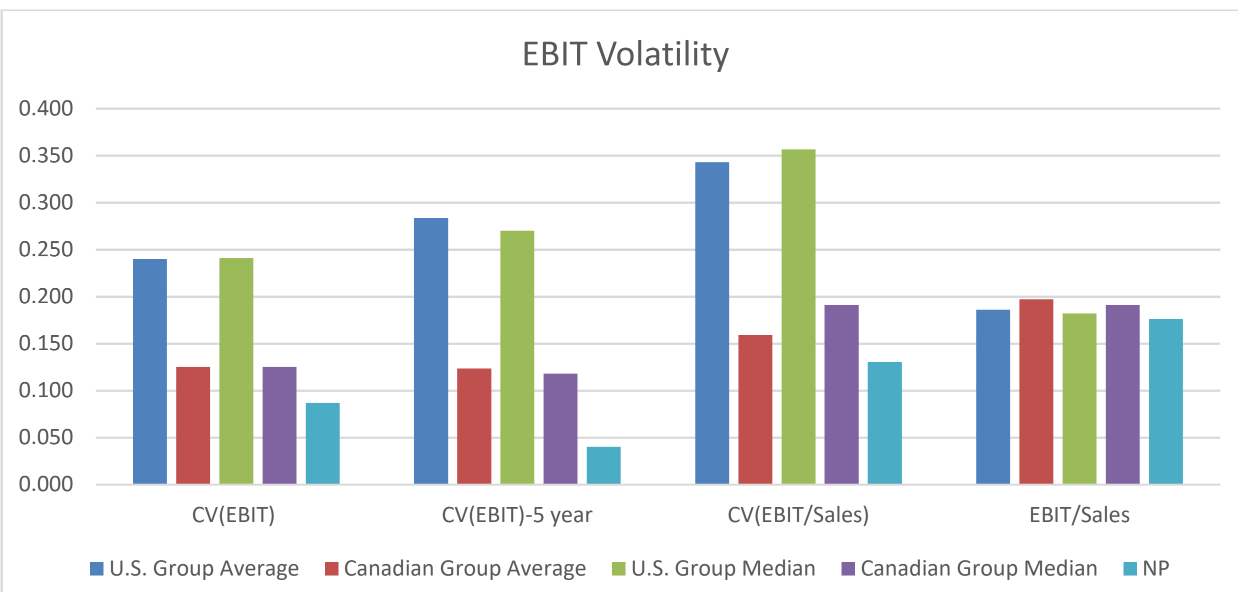


Table 8 confirms that the patterns displayed in Figure 7 are not driven by the use of averages or medians, as it reports the results for all U.S. and Canadian firms used in the comparison groups. Table 8 clearly shows that all three CV-EBIT measures are higher for each U.S. utility than for NP – much, much higher in most cases. This also true when the U.S. CV-EBIT measures are compared to the other Canadian firms, with the exception of the last two measures for NSTAR which are lower than one or two Canadian firms respectively (but not NP). Again, these results confirm that NP has very low business risk, as do the other Canadian regulated utilities examined.

TABLE 8

COEFFICIENT OF VARIATION OF EBIT ESTIMATES FOR ALL FIRMS (1995-2014)

		Coefficient of Variation of EBIT Measures (1995-2014)			
U.S. Firms		**CV(EBIT)**	**CV(EBIT)-5 year**	**CV(EBIT/Sales)**	**EBIT/Sales**
	Allette inc.	0.300	0.298	0.206	0.182
	Duke Energy Inc.	0.241	0.395	0.459	0.193
	Great Plains Energy	0.252	0.270	0.357	0.180
	OGE Energy	0.218	0.148	0.422	0.152
	Pinaccle West Corp.	0.161	0.167	0.261	0.222
	Westar Energy	0.333	0.580	0.545	0.204
	NSTAR*	0.176	0.128	0.151	0.170
	U.S. Group Average	**0.240**	**0.284**	**0.343**	**0.186**
Canadian Firms					
	NSPI	0.121	0.118	0.231	0.257
	Enbridge Gas	0.129	0.115	0.191	0.191
	Gaz Metro**	0.125	0.137	0.054	0.142
	Canadian Group Average	**0.125**	**0.124**	**0.159**	**0.197**
Newfoundland Power	**NP**	**0.087**	**0.040**	**0.130**	**0.176**
	U.S. Group Median	0.241	0.270	0.357	0.182
	Canadian Group Median	0.125	0.118	0.191	0.191

NOTES: U.S. data was obtained from the Compustat database. Canadian data was obtained from annual reports 1995-2014 for Newfoundland Power, Enbridge Gas Distribution Inc., Emera (for NSPI), and from 2009-2015 for Valener (for Gaz Metro).

* Data only available to 2011. Subsidiary of Eversource.
** Data only available 2009-2015.

Finally, while U.S. regulated utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Canadian counterparts, including NP. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts – although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions. However, the higher business risk displayed by U.S. utilities is completely consistent with the observation that U.S. utilities have higher betas than Canadian ones, as noted in Figure 12 of Mr. Coyne's evidence for example. Higher betas indicate higher investment (i.e., total) risk. Since U.S. utilities have higher allowed ROEs and equity ratios, on average, it is reasonable to conclude that the higher betas may be attributed to the higher business risk faced by U.S. utilities.

In fact, it is possible to estimate the "unlevered" beta for a company, which is the beta after adjusting for the firm's level of financial leverage. This is commonly viewed as the beta on the firm's underlying assets or operations. Intuitively, the unlevered beta will be related to business risk. I will illustrate using Mr. Coyne's evidence for U.S. and Canadian betas of 0.70 and 0.64 respectively, for example.[4] I will then combine these beta estimates with the implied debt-equity (D/E) ratios using the debt-to-capitalization ratios of 0.52 and 0.65 respectively for U.S. and Canadian utilities as provided by Mr. Coyne in Appendix A, Exhibit JMC-2. These imply D/E ratios of 1.08 and 1.86 for U.S. and Canadian utilities, respectively. Using the commonly used equation to determine unlevered betas (i.e., where B(unlevered) = B(levered)/(1 + D/E)), we can then see that the implied "unlevered" betas for Canadian and U.S. utilities are 0.22 and 0.34 respectively. This also implies lower business risk for Canadian utilities, consistent with the evidence provided above for the CV-EBIT measures.

3.2.5 Concluding Remarks Regarding Business Risk

[4] I use these estimates **for illustrative purposes only**, since they illustrate the "relative" relationship between U.S. and Canadian utility betas – i.e., U.S. utility betas are higher. For the record, both betas appear unreasonably high to me. This is at least partially due to the use of "adjusted" betas, which adjust for betas tendency to gravitate to one. This adjustment does not make sense for utility betas, which are not likely to gravitate to a level anywhere nearly as high as one, since they are much less risky than the average company trading in the market.

The qualitative analysis above confirms that NP continues to be a low business risk electric distribution utility operating in a very supportive regulatory environment, similar to the conclusions reached by the Board in previous decisions, and also consistent with the analyses of credit rating agencies of NP. My quantitative analysis provides strong support for these qualitative conclusions, as NP is shown to display much lower volatility in operating income than comparable U.S. firms, and slightly below Canadian comparable utilities. As such, I conclude that NP continues to be a very low business risk firm.

3.3 Financial Risk

In this section, I examine the financial risk of NP by reference to a(n):

(1) comparison of allowed ROEs and equity ratios with other Canadian utilities;

(2) comparison of NP's credit metrics to other Canadian utilities; and,

(3) examination of the effect on NP's credit metrics of changes in allowed ROEs and equity ratios from the existing base case.

My analysis concludes that NP has lower financial risk than its Canadian counterparts on average, and that there is definite room for the Board to decrease the allowed equity ratio, without affecting NP's ability to access credit on reasonable terms.

3.3.1 Allowed ROEs and Equity Ratios

Tables 9 and 10 provide data on allowable ROEs and equity ratios for Canadian electric and gas distributors from 2011 to 2015. The data is taken from the 2013, 2014 and 2015 Concentric reports that were provided in response to CA-NP-157. I have no reason to dispute the integrity of the data and have verified from other sources the 2015 data, which is the primary focus of my discussion.

TABLE 9

ALLOWED ROES (%) - 2011-2015

	2011	2012	2013	2014	2015
Canadian Electric Distributors					

ATCO Electric Ltd.	8.75	8.75	8.30	8.30	8.30
ENMAX Power Corp.	8.75	8.75	8.30	8.30	8.30
EPCOR Distribution Inc.	8.75	8.75	8.30	8.30	8.30
FortisAlberta Inc.	8.75	8.75	8.30	8.30	8.30
FortisBC Inc.	9.90	9.90	9.15	9.15	9.15
Hydro-Quebec Distribution	7.32	6.37	6.19	8.20	8.20
Maritime Electric Company Limited	9.75	9.75	9.75	9.75	9.75
Nova Scotia Power Inc.	9.35	9.20	9.00	9.00	9.00
Ontario's Electric Distributors	9.58	9.12	8.98	9.36	9.30
Saskatchewan Power Corp.	7.40	7.40	8.50	8.50	8.50
Average	**8.83**	**8.67**	**8.48**	**8.72**	**8.71**
Median	**8.75**	**8.75**	**8.40**	**8.40**	**8.40**
Canadian Gas Distributors					
AltaGas Utilities Inc.	8.75	8.75	8.30	8.30	8.30
ATCO Gas	8.75	8.75	8.30	8.30	8.30
Enbridge Gas Distribution Inc.	8.39	8.39	8.93	9.36	9.30
FortisBC Energy Inc.	9.50	9.50	8.75	8.75	8.75
Gaz Metro Limited Partnership	9.09	8.90	8.90	8.90	8.90
SaskEnergy Inc.	8.75	8.75	8.75	8.75	7.74
Union Gas Limited	8.54	8.54	8.93	8.93	8.93
Average	**8.82**	**8.80**	**8.69**	**8.76**	**8.60**
Median	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**
Including All Firms in Both Groups					
Average	**8.83**	**8.72**	**8.57**	**8.73**	**8.67**
Median	**8.75**	**8.75**	**8.75**	**8.75**	**8.50**
Newfoundland Power	**8.38**	**8.80**	**8.80**	**8.80**	**8.80**

Table 9 shows that NP has provided an allowable ROE over this period that is slightly above the average and/or median levels for other Canadian distributors. For example, with a 2015 allowable ROE of 8.8%, NP is slightly above the average (median) for Canadian gas distributors of 8.60% (8.75%), and also slightly above the figures for Canadian electric distributors of 8.71% (8.40%). If we aggregate the data for both types of distributors NP's allowed ROE is slightly above the average of 8.67% and the median of 8.50%. In other words, NP's allowed ROE is close to the average for Canadian distribution utilities. With respect to the equity ratios provided in Table 10, we can see that NP's equity ratio of 45% is well above the mean and medians in the 38-40% range for each group, and for both groups combined. In fact, 45% is

3% higher than the next highest equity ratio, and 10 of the 17 utilities listed in this table have equity ratios of 40% or lower.

TABLE 10

EQUITY RATIOS (%) - 2011-2015

	2011	2012	2013	2014	2015
Canadian Electric Distributors					
ATCO Electric Ltd.	39.00	39.00	38.00	38.00	38.00
ENMAX Power Corp.	41.00	41.00	40.00	40.00	40.00
EPCOR Distribution Inc.	41.00	41.00	40.00	40.00	40.00
FortisAlberta Inc.	41.00	41.00	40.00	40.00	40.00
FortisBC Inc.	40.00	40.00	40.00	40.00	40.00
Hydro-Quebec Distribution	35.00	35.00	35.00	35.00	35.00
Maritime Electric Company Limited	42.70	41.70	43.50	43.10	41.90
Nova Scotia Power Inc.	40.00	37.50	37.50	37.50	37.50
Ontario's Electric Distributors	40.00	40.00	40.00	40.00	40.00
Saskatchewan Power Corp.	40.00	40.00	40.00	40.00	40.00
Average	**39.97**	**39.62**	**39.40**	**39.36**	**39.24**
Median	**40.00**	**40.00**	**40.00**	**40.00**	**40.00**
Canadian Gas Distributors					
AltaGas Utilities Inc.	43.00	43.00	42.00	42.00	42.00
ATCO Gas	39.00	39.00	38.00	38.00	38.00
Enbridge Gas Distribution Inc.	36.00	36.00	36.00	36.00	36.00
FortisBC Energy Inc.	40.00	40.00	38.50	38.50	38.50
Gaz Metro Limited Partnership	38.50	38.50	38.50	38.50	38.50
SaskEnergy Inc.	37.00	37.00	37.00	37.00	37.00
Union Gas Limited	36.00	36.00	36.00	36.00	36.00
Average	**38.50**	**38.50**	**38.00**	**38.00**	**38.00**
Median	**38.50**	**38.50**	**38.00**	**38.00**	**38.00**
<u>Including All Firms in Both Groups</u>					
Average	**39.36**	**39.16**	**38.82**	**38.80**	**38.73**
Median	**40.00**	**40.00**	**38.50**	**38.50**	**38.50**
Newfoundland Power	**45.00**	**45.00**	**45.00**	**45.00**	**45.00**

The analysis above shows that NP has lower financial risk than the average Canadian distributor based solely on allowed ROEs and equity ratios. While NP's allowed ROE is very close to the average, the allowed equity ratio is much, much higher, indicating lower financial risk, all else being equal. It is worthy of note at this time that this lower financial risk does not seem warranted due to higher business risk for NP versus similar Canadian utilities based on the discussion in the previous section – recall that the analysis in that section concluded that NP had average-to-slightly below average business risk when compared to other Canadian utilities, and much less than U.S. utilities.

3.3.2 Credit Metric Comparisons

In this section, I compare the credit metrics of NP to those for some comparable Canadian utilities. Unfortunately, due to variances in size, ownership structure and the availability of public information such as debt rating reports, and/or financial statement information, the sample size is limited. Table 11 provides the statistics for the three main ratios used by DBRS that were obtained from the most recent DBRS reports that I was able to find.[5] Using the ratios as calculated by one source should enhance the consistency in the calculation of such ratios.

TABLE 11

DEBT RATINGS AND CREDIT METRICS - 2014

	DBRS RATINGS AND CREDIT METRICS			
	Issuer Rating	**Total Debt to Capital**	**CF/Debt**	**EBIT Interest Coverage**
Canadian Regulated Utilities				
1. CU Inc.	A (high)	60.20%	12.60%	2.67
2. Enbridge Gas Distribution Inc.	A	55.70%	16.40%	2.60
3. FortisAlberta Inc.	A (low)	56.70%	17.00%	2.18
4. FortisBC Inc.	A (low)	58.40%	14.10%	2.44
5. Gaz Metro Limited Partnership	A	67.20%	15.70%	1.82
6. Nova Scotia Power Inc.	A (low)	61.20%	15.80%	2.19
Average		**60.88%**	**15.65%**	**2.16**
Median		**59.80%**	**15.75%**	**2.19**
Newfoundland Power (Aug 21, 2015 DBRS)				
2014	A	**55.30%**	**17.70%**	**3.06**

[5] The figures are for 2014 for all firms except for Enbridge Gas Distribution Inc., which are for 2013, and Metro Gaz which are for 2015.

Data obtained from DBRS Reports: 1. April 12, 2015; 2. March 12, 2014 - report 2013 figures; 3. December 16, 2015; 4. April 8, 2015; 5. December 21, 2015 (for Gaz Metro Inc., based on the guarantee of GMLP) – report 2015 figures; and, 6. February 18, 2015.

The results provided in Table 11 are consistent with what one would expect based on the discussion in the previous sub-section – namely, according to analysis of credit metrics provided by DBRS, NP appears to have lower financial risk than its Canadian counterparts. In particular, NP has a debt-to-capital ratio of 55% that is well below the group average or median of 60%, and is in fact below the ratio for all firms in the sample. Similarly, NP's interest coverage ratio of 3.06 for 2014 is well above the group average and median figures of 2.16 and 2.19 - it is also higher than the coverage ratio for each firm in the sample. NP's 2014 CF/Debt ratio of 17.7% is also higher than those for all of the other listed Canadian utilities.

NP's debt-to-capital ratio of 55% lies on the cut-off point between an A and AA rating for low business risk firms, according to DBRS criteria. The EBIT coverage ratio for NP is well above the 2.8 cut-off value for a AA assessment, while their CF/Debt ratio also slightly exceeds the 17.5% AA cut-off point. Therefore, it is not surprising their A rating was confirmed, since their metrics suggest they lie somewhere between the bottom half of the AA category and the top half of the A category, and even if they deteriorated somewhat they would be well in the "A range." The average debt-to-capital ratio for the other Canadian firms lies firmly in the middle of the A category (i.e., 55-65%). The interest coverage and CF/Debt ratios for the sample group also fall squarely in the A range, also consistent with their range of A(low) to A(high) ratings. It is noteworthy that NP has an A rating, falling in the middle of the range of ratings for the firms in this group, despite the fact that the group firms possess weaker credit metrics than NP. This also implies that even if NP's metrics were weaker they would probably maintain their A rating status, given their below-to-average business risk discussed previously.

3.3.3 Credit Metric Scenarios

In this section I evaluate the potential impact of various allowed ROE and equity ratio scenarios on the credit metrics of NP. I use the data provided in Exhibit 3 of NP's evidence to construct the base case for 2013-2017. I then estimate the primary credit metrics relied upon by DBRS and Moody's respectively. Finally, I provide forecasts of what would happen to these metrics under various assumptions regarding ROE and equity ratios, and discuss the implications. For ease of reference, Table 12 provides the ranges for the metrics used in assessing utilities' financial risk by Moody's and DBRS (for low business risk firms – which is what DBRS uses in assessing utilities such as NP).

TABLE 12

CREDIT METRIC CRITERIA

Moody's Metrics	**A**	**Baa**
(CFO pre-WC + Interest)/Interest	4.5 to 6.0	3 to 4.5
CFO pre-WC/Debt	19 to 27%	11 to 19%
(CFO pre-WC - Dividends) /Debt	15 to 23%	7 to 15%
Debt/Capitalization	40 to 50%	50 to 59%

		(Low Bus. Risk)	
DBRS Metrics	**AA**	**A**	**BBB**
Cash flow to debt	above 17.5%	12.5 to 17.5%	10.0 to 12.5%
Debt to Capital	below 55%	55 to 65%	65-75%
EBIT to Interest	Above 2.8	1.8 to 2.8	1.5 to 1.8

Table 13 presents the base case scenario using the data provided in Exhibit 3 by NP, based on existing rates and equity ratios. The data shows that from 2013 to 2017, under existing rates and according to NP's own data, that NP's metrics remain solid and lie at the high Baa to low A range for Moody's, and lie at the high A to low AA range according to DBRS metrics. In addition, their interest coverage remains well above 2.0, never falling below 2.36. In other words, NP's metrics continue to look strong for 2015-2017 at existing rates, using NP's own data, and assuming no changes in the equity ratio.

TABLE 13

CREDIT METRIC ESTIMATES – 2013-2017

Base Case

Moody's Metrics	**2013**	**2014**	**2015E**	**2016E**	**2017E**	**NP**
(CFO pre-WC + Interest)/Interest	3.61	3.65	3.77	3.90	3.78	Baa(mid-high)
CFO pre-WC/Debt	18.75%	18.40%	18.01%	18.20%	17.43%	Baa(high)
(CFO pre-WC - Dividends) /Debt	14.14%	13.95%	16.20%	14.88%	15.41%	Baa(high) to A(low)
Debt/Capitalization	54.07%	54.51%	54.45%	54.12%	54.15%	Baa(mid)

DBRS Metrics - calculated						
Cash flow to debt	18.75%	18.40%	18.01%	18.20%	17.43%	A(high) to AA(low)
Debt to Capital	54.34%	54.85%	54.72%	54.38%	54.39%	AA(low)
EBIT to Interest	2.48	2.52	2.57	2.49	2.36	A(high)

The discussion with respect to business risk in Section 3.2 concluded that NP is a below-average-to-average business risk Canadian utility. The comparison of NP's allowed ROEs and equity ratios and its recent credit metrics to other Canadian utilities showed that NP has lower financial risk. This implies that the Board should consider a decrease in NP's equity ratio to bring it in line with Canadian averages. Of course, such changes would affect NP's credit metrics, so it is worth examining the extent of such. Similarly, as allowed ROEs provided by regulators have been declining in recent years in response to lower interest rate levels among other things, it is also of interest to examine what credit metrics would result from considering alternative ROEs. With this in mind, I have prepared an analysis of projected credit metrics under various ROE scenarios (i.e., 7.5%, 8.0%, 8.3%, 8.5% and 8.8%) first using the existing equity ratio of 45%, and then using a 40% equity ratio. The results using a 45% equity ratio are presented in Table 14.

TABLE 14

2016-17 CREDIT METRIC ESTIMATES USING A 45% EQUITY RATIO

	USING 45% Equity Ratio					
2016 Metrics	**ROE**	**ROE**	**ROE**	**ROE**	**ROE**	
	7.50%	**8.00%**	**8.30%**	**8.50%**	**8.80%**	**NP**
Moody's Metrics						
(CFO pre-WC + Interest)/Interest	3.89	3.96	4.00	4.02	4.06	Baa(high)
CFO pre-WC/Debt	18.19%	18.60%	18.85%	19.01%	19.26%	Baa(high) to A(low)
(CFO pre-WC - Dividends) /Debt	14.87%	15.28%	15.53%	15.69%	15.94%	Baa(high) to A(low)
Debt/Capitalization	54.12%	54.12%	54.12%	54.12%	54.12%	Baa(mid)
DBRS Metrics						
Cash flow to debt	18.19%	18.60%	18.85%	19.01%	19.26%	AA(low)
Debt to Capital	54.38%	54.38%	54.38%	54.38%	54.38%	AA(low)
EBIT to Interest	2.40	2.49	2.55	2.64	2.64	A(high)
2017 Metrics	**ROE**	**ROE**	**ROE**	**ROE**	**ROE**	
	7.50%	**8.00%**	**8.30%**	**8.50%**	**8.80%**	
Moody's Metrics						**NP**
(CFO pre-WC + Interest)/Interest	3.88	3.95	3.99	4.01	4.05	Baa(high)
CFO pre-WC/Debt	18.04%	18.45%	18.70%	18.86%	19.11%	Baa(high) to A(low)

(CFO pre-WC - Dividends) /Debt	16.02%	16.43%	16.68%	16.84%	17.09%	A(low)
Debt/Capitalization	54.15%	54.15%	54.15%	54.15%	54.15%	Baa(mid)
DBRS Metrics						
Cash flow to debt	18.04%	18.45%	18.70%	18.86%	19.11%	AA(low)
Debt to Capital	54.39%	54.39%	54.39%	54.39%	54.39%	AA(low)
EBIT to Interest	2.41	2.51	2.56	2.60	2.66	A(high)

Table 14 shows that for 2016 and 2017, using the current 45% equity ratio, and under various ROE scenarios and according to NP's own data, that NP's metrics would remain solid and lie at the high Baa to low A range for Moody's, and lie at the high A to low AA range according to DBRS metrics. In addition, NP's interest coverage remains well above 2.0, never falling below 2.4. This is true under all of the allowed ROE figures. This suggests that the PUB could lower the ROE significantly at the current allowed equity ratio and the credit metrics would remain strong.

Since the focus of my discussion is on the allowable equity ratio, I will now proceed to see how reducing it would impact credit metrics. Table 15 examines the credit metric estimates using a 40% equity ratio. As in Tables 13 and 14, I use the financial statement data provided in Exhibit 3 by NP to construct the estimates. The main assumptions that I make are that: (1) the marginal tax rates for 2016 and 2017 would be those implied in Exhibit 3 of NP's data; (2) depreciation would equal the estimates provided in Exhibit 3; (3) the items "excluding net income" that are used to estimate the CFO pre-WC estimates provided in Exhibit 3 would remain unchanged, so that CFO pre-WC can be recalculated by adjusting for changes in the net income figure only; (4) common equity would remain at the same dollar levels reported in Exhibit 3; (5) common equity will earn the allowed ROE resulting in the appropriate figure for net earnings available to common shareholders; and, (6) new long-term debt would be issued at 4.45% (i.e., the yield on the September 2015 NP bond issue) and used to bring the equity ratio down to 40%, with the additional interest expense being added to the interest expense estimates for 2016 and 2017 provided in Exhibit 3 of NP's evidence.

TABLE 15

2016-17 CREDIT METRIC ESTIMATES USING A 40% EQUITY RATIO

2016 Metrics	**ROE 7.50%**	**ROE 8.00%**	**ROE 8.30%**	**ROE 8.50%**		**NP**
Moody's Metrics						

(CFO pre-WC + Interest)/Interest	3.50	3.56	3.59	3.62	Baa(mid)
CFO pre-WC/Debt	14.91%	15.25%	15.45%	15.59%	Baa(high)
(CFO pre-WC - Dividends) /Debt	12.19%	12.53%	12.73%	12.87%	Baa(high)
Debt/Capitalization	59.00%	59.00%	59.00%	59.00%	Baa(low)
DBRS Metrics					
Cash flow to debt	14.91%	15.25%	15.45%	15.59%	A(high)
Debt to Capital	59.24%	59.24%	59.24%	59.24%	A(mid)
EBIT to Interest	2.21	2.29	2.34	2.37	A(mid) to A(high)
2017 Metrics	**ROE 7.50%**	**ROE 8.00%**	**ROE 8.30%**	**ROE 8.50%**	
Moody's Metrics					**NP**
(CFO pre-WC + Interest)/Interest	3.49	3.55	3.58	3.61	Baa(mid)
CFO pre-WC/Debt	14.78%	15.12%	15.32%	15.46%	Baa(high)
(CFO pre-WC - Dividends) /Debt	13.13%	13.46%	13.67%	13.80%	Baa(high)
Debt/Capitalization	59.04%	59.04%	59.04%	59.04%	Baa(low)
DBRS Metrics					
Cash flow to debt	14.78%	15.12%	15.32%	15.46%	A(high)
Debt to Capital	59.28%	59.28%	59.28%	59.28%	A(mid)
EBIT to Interest	2.22	2.30	2.35	2.38	A(mid) to A(high)

Table 15 shows that if the equity ratio was reduced to 40%, NP's credit metrics for 2016 and 2017 would remain firmly in the Baa range for Moody's, and in the mid-to-high A range for DBRS, if the allowed ROE is also reduced. Similarly, the interest coverage ratio remains well above 2, and never falls below 2.2, under any scenario presented. In other words, NP's credit metrics would remain solid if the PUB reduced NP's allowable equity ratio to 40% and also reduced the allowed ROE.

3.3.4 Concluding Remarks Regarding Financial Risk

The discussion in Section 3.3.1 shows that NP has lower financial risk than other Canadian utilities based upon a combination of an allowable ROE which is about average and equity ratios which are much higher than average. Given this attractive ROE to equity ratio combination, it is not surprising that NP displays superior credit metric ratios to its Canadian peers, as discussed in Section 3.3.2. An examination of credit metric sensitivity to changes in allowed ROEs and equity ratios indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and the allowable ROE was also reduced.

3.4 Capital Structure Recommendation

Both the qualitative discussion and quantitative analysis in Section 3.2 show clearly that NP has low business risk, similar or slightly lower than that for similar Canadian firms. Sections 3.3.1 and 3.3.2 demonstrate that NP currently has less financial risk than other Canadian utilities based on an examination of allowable ROEs and equity ratios, and of existing credit metrics. Finally, the examination of NP’s credit metric sensitivity in Section 3.3.3 indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and if the allowed ROE was also reduced.

It is not clear why a low business risk firm like NP requires an equity ratio that is much higher than average, while being allowed to earn an ROE that is around average. I recommend that the Board reduce NP’s equity ratio to 40%, which would bring it in line with Canadian averages. The additional “above average” 5-6% equity thickness is not warranted based on NP’s business risk, nor is it required to maintain solid credit metrics that will permit NP to maintain its ability to raise credit on reasonable terms.

Attachment 7: Newfoundland cost of capital proceedings in 2018

BEFORE THE NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

EVIDENCE OF DR. SEAN CLEARY, CFA,

BMO PROFESSOR OF FINANCE

SUBMITTED ON BEHALF OF:
THE NEWFOUNDLAND CONSUMER ADVOCATE

REPORT ON CAPITAL STR UCTURE & RELATED ISSUES

September 25, 2018

TABLE OF CONTENTS

1. INTRODUCTION

1.1 Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am currently the Director of the Master of Finance program and the BMO Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I served as an expert witness on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016. I have also served in this capacity on several occasions on behalf of the Office of the Utilities Consumer Advocate of Alberta (the **"UCA"**), including generic cost of capital ("**GCOC**") proceedings in 2017-18 (Proceeding 22635), 2017 (Proceeding ID 22570), and 2013-2014 (Proceeding ID 2191). I also served on behalf of the UCA in regulated rate option ("**RRO**") proceedings in 2017-18 (Proceeding 22635), 2017 (Proceeding 22357), and (Proceeding ID 2941) in 2014.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of 30 publications. My work has been cited close to 3,200 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of equity issues. I have authored or co-authored 13 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Appendix A to my evidence.

1.2 Purpose of Testimony

The Consumer Advocate of Newfoundland and Labrador has requested that I recommend an appropriate capital structure (i.e., equity ratio) for Newfoundland Power during the 2018 General Rate Application (GRA) proceedings.

1.3 Summary of Capital Structure Recommendations

The Canadian economy is forecast to grow slowly, but positively, over 2016 and 2017 as a result of low oil and commodity prices and a low Canadian dollar, which is beginning to provide anticipated benefits. The Newfoundland and Labrador economy has been hit harder than most provinces and economic growth is expected to be negative in 2015 and 2016, before returning to positive territory in 2017 and beyond. Newfoundland Power (NP) has been resilient to such economic downturns in the past, and I expect that it will be this time around.

My qualitative analysis confirms that NP continues to be a low business risk electric distribution utility operating in a very supportive regulatory environment, similar to the conclusions reached by the Board in previous decisions, and also consistent with the analyses of credit rating agencies of NP. My quantitative analysis provides strong verification of these qualitative conclusions, as NP is shown to display much lower volatility in operating income than comparable U.S. firms, and slightly below Canadian comparable utilities. As such, I conclude that NP continues to be a very low business risk firm.

My analysis in section 3.3.1 shows that NP has lower financial risk than other Canadian utilities based upon a combination of an allowable ROE which is about average and equity ratios which are much higher than average. Given this attractive ROE to equity ratio combination, it is therefore not surprising that NP has displayed superior credit metric ratios than its Canadian peers, as discussed in Section 3.3.2. An examination of credit metric sensitivity to changes in allowed ROEs and equity ratios indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and the allowable ROE was also reduced.

It is not clear why a low business risk firm like NP requires an equity ratio that is much higher than average, while being allowed to earn an ROE that is around average. I recommend that the Board reduce the equity ratio to 40%, which would bring it in line with, but still slightly above, Canadian utility averages. The additional “above average” 5-6% equity thickness is not warranted based on NP’s business risk, nor is it required to maintain solid credit metrics that will permit NP to maintain its ability to raise credit on reasonable terms.

2. ECONOMY OVERVIEW

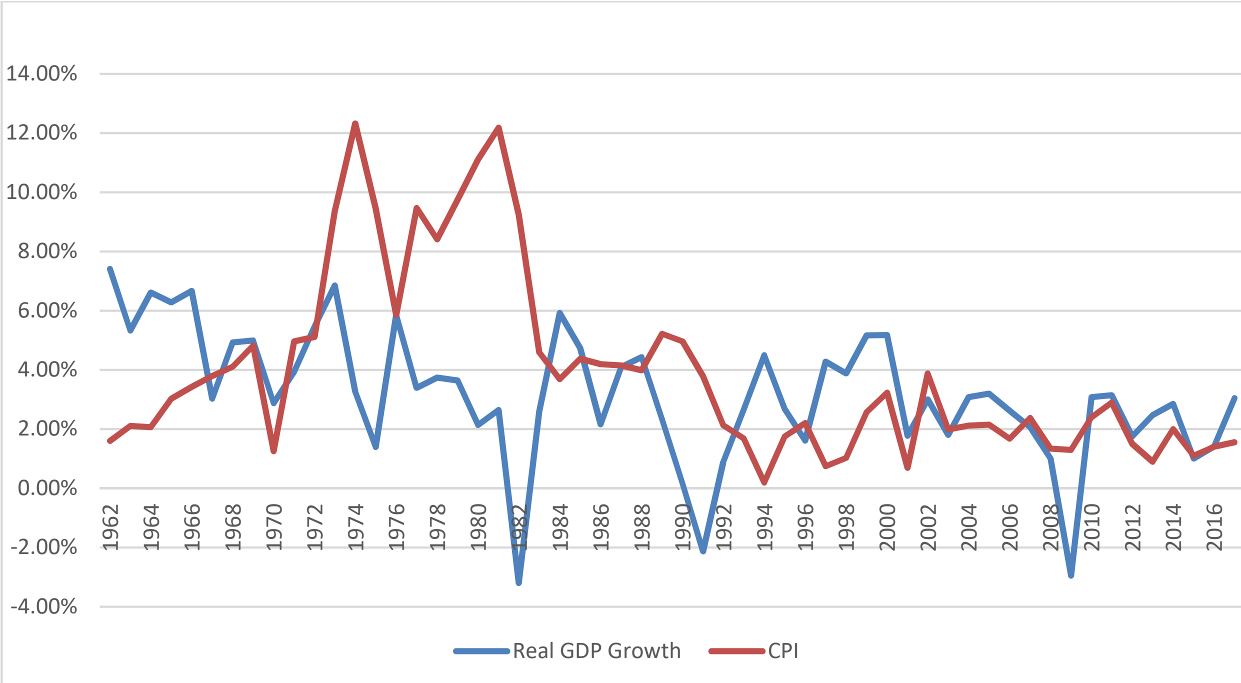
2.1 The Canadian Economy

2.1.1 Historical Evidence

The figure below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index (CPI) over the 1962 to 2017 period. The graph shows that real GDP growth has generally been in the 2 to 6 percent range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average for GDP growth over the entire period was 3.2% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.5% (median 2.7%) over the 1992 to 2017 period. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from the figure, and also as measured by the standard deviation reported in Table 1.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2017)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2017)

	1962-2017 (%)		1992-2017 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.16	3.92	2.51	1.80
Median	3.07	2.97	2.67	1.72
Max	7.41	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.19	3.10	1.63	0.83

Data Source: Statistics Canada.

Figure 1 also reports annual changes in CPI, which averaged 3.9% (median 3.0%) over the entire period. These summary stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average of 1.8% (median 1.7%). CPI growth has also been very stable during this latter period, which is obvious from the graph, and also by the huge decline in standard deviation from 3.1% to 0.8%. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2 Global Economic Activity

The global economy has faced several challenges since 2008, but is expected to grow at a solid pace in 2018 and 2019. For example, Table 2 shows the April 2018 Consensus Economics Inc. Forecasts for average global real GDP growth figures of 3.3% and 3.2% respectively, while the Bank of Canada's July 2018 Monetary Policy Report (MPR)[1] estimates were higher at 3.8% and 3.5%. Table 2 shows that the expected global improvements are based partly on expectations that the U.S. economy will continue to grow steadily over 2018 and 2019 in the 2.5-3.1% range, while the Euro zone will continue to rebound back close to normal growth levels with expected growth rates of 1.6-2.4% for 2018-19.

[1] Source: https://www.bankofcanada.ca/wp-content/uploads/2018/07/mpr-2018-07-11.pdf.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2018-2019)

Real GDP Growth (%)	2018		2019	
	Consensus	Bank of Canada	Consensus	Bank of Canada
World	3.3	3.8	3.2	3.5
U.S.	2.8	3.1	2.6	2.5
Euro Zone	2.4	2.2	1.9	1.6

Source: Consensus Economics Inc. (April 2018) and Bank of Canada MPR (July 2018).

The Bank of Canada notes in its' July 2018 MPR that global growth will remain solid, with trade tensions posing a risk to this outlook through their potential influence on trade and investment. The factors driving growth include the robust U.S. economy and accommodative global financial conditions, despite recent movements by the U.S. in particular to reduce monetary stimulus. The Bank further notes that other economies continue to grow, albeit at a slower pace than the U.S., and with some economies being affected adversely by recent increases in oil prices. They also expect strong growth in emerging market economies, albeit with rising risks in some of them. With respect to China, the Bank stated that "Economic growth is still anticipated to moderate from around 6 1/2 per cent in 2018 to around 6 per cent in 2020, as part of the continued transition to more sustainable growth."

2.1.3 Today's Outlook

The Bank's July 2018 MPR notes that "the Canadian economy continues to operate close to full capacity, and GDP is expected to expand somewhat faster than potential." The Bank expects the contribution from consumer spending to moderate in response to higher interest rates and new mortgage rules, despite support from rising wages and strong employment levels. The Bank notes that there is an ongoing shift from consumer spending to business investment and exports. This growth in investment and exports is occurring despite the risks posed by escalating trade tensions, including ongoing NAFTA negotiations. This growth in investment is supported by the results of the Bank's "Business Outlook Survey – Summer 2018," which reported an increase in the summary BOS Indicator to near record highs, reflecting business optimism.[2] Economic growth is being supported by accommodative monetary conditions and foreign demand, while oil price increases have helped some industries and jurisdictions. Trade policy uncertainty and tariffs serve to dampen this potential growth.

Taking all of these factors into consideration the Bank forecast real GDP growth of 2.0% in 2018, 2.2% in 2019 and 1.9% in 2020. Table 3 shows that the 2018 and 2019 forecasts are in line with the April 2018 Consensus Economics' forecasts (2.0% and 1.9%), and with those of the IMF (2.3% and 2.0%) and the OECD (2.2% and 2.0%).

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2018-2019)

Conf. Board of Canada	1.9	2.2
CIBC World Markets	2.1	1.6
IHS Markit	2.4	2.3
Citigroup	2.1	2.1
BMO Capital Markets	2.0	1.8
Desjardins	2.1	1.9
Econ Intell Unit	2.0	1.7
EconoMap	2.1	1.9
Oxford Economics	1.8	2.1
JP Morgan	1.9	1.7
National Bank	2.5	1.8
RBC	1.9	1.6
TD Bank	2.0	1.9
University of Toronto	1.6	2.1
Scotia Econ	2.2	2.1
Informetrica	2.2	1.8
Stokes Econ Consulting	2.3	2.0
Inst Fiscal Studies	1.9	1.8
Capital Economics	1.5	1.3
Average	**2.0**	**1.9**
Median	**2.1**	**1.9**
Max	**2.5**	**2.3**
Min	**1.5**	**1.3**
IMF (Jan 18)	**2.3**	**2.0**
OECD (Mar 18)	**2.2**	**2.0**
Bank of Canada (July 2018)	**2.0**	**2.2**

[2] Source: Bank of Canada "Business Outlook Survey": https://www.bankofcanada.ca/2018/06/business-outlook-survey-summer-2018/.

Source: Consensus Economics Inc. (April 2018) and Bank of Canada MPR (July 2018).

The Bank notes that "labour market conditions remain healthy, but growth of employment and average hours worked has slowed from last year's strong pace (Chart 7). Likewise, after declining notably in 2017, the unemployment rate to date this year has remained relatively steady, near its 40-year low." Further, they note that core inflation remained close to 2%, "consistent with an economy operating near potential." They forecast that total CPI inflation would hit 2.5% in the last two quarters of 2018 reflecting the impact of "higher gasoline prices in recent months, the impact of minimum wage increases, newly imposed tariffs and exchange rate pass-through."

Based on the discussion above, the Bank predicts inflation rates of 2.4% in 2018, 2.2% in 2019, and 2.1% in 2020, all within range of its target rate. The Bank's total inflation projections for 2018 were slightly above, but in line with the Consensus Economics' forecasts of 2.2% and 2.0%, as well as with those of the IMF and OECD, all of which can also be found in Table 4.

TABLE 4

CPI FORECASTS – CANADA (2018-2019)

CPI Forecast	2018	2019
Conf. Board of Canada	2.0	1.9
CIBC World Markets	2.4	2.0
IHS Markit	2.1	2.0
Citigroup	2.1	2.0
BMO Capital Markets	2.2	2.1
Desjardins	2.4	2.0
Econ Intell Unit	1.9	1.8
EconoMap	2.2	2.1
Oxford Economics	2.2	2.0
JP Morgan	2.1	2.0
National Bank	2.3	2.1
RBC	2.6	1.9
TD Bank	2.3	2.0
University of Toronto	2.5	2.1
Scotia Economics	2.2	2.3
Informetrica	2.1	2.1
Stokes Econ Consulting	1.9	2.0
Inst Fiscal Studies	2.1	1.9
Capital Economics	2.3	1.5

Average	**2.2**	**2.0**
Median	**2.2**	**2.0**
Max	**2.6**	**2.3**
Min	**1.9**	**1.5**
IMF (Jan 18)	**2.3**	**2.0**
OECD (Mar 18)	**2.2**	**2.0**
Bank of Canada (Jan 2018)	**2.4**	**2.2**

Source: Consensus Economics Inc. (April 2018) and Bank of Canada MPR (July 2018).

The Bank states that "The ongoing shift toward protectionist global trade policies remains the most important source of uncertainty surrounding the outlook." The associated risk can affect not only investment and exports, but also global economic health and consumer spending from those working in affected industries. Noting this, the Bank identified the following key risks that could impact its' inflation forecasts: (a) weaker Canadian investment and exports; (b) sharp tightening of global financial conditions; (c) stronger real GDP growth in the United States; (d) stronger consumption and rising household debt in Canada; and, (e) a pronounced decline in house prices in overheated markets in Canada.

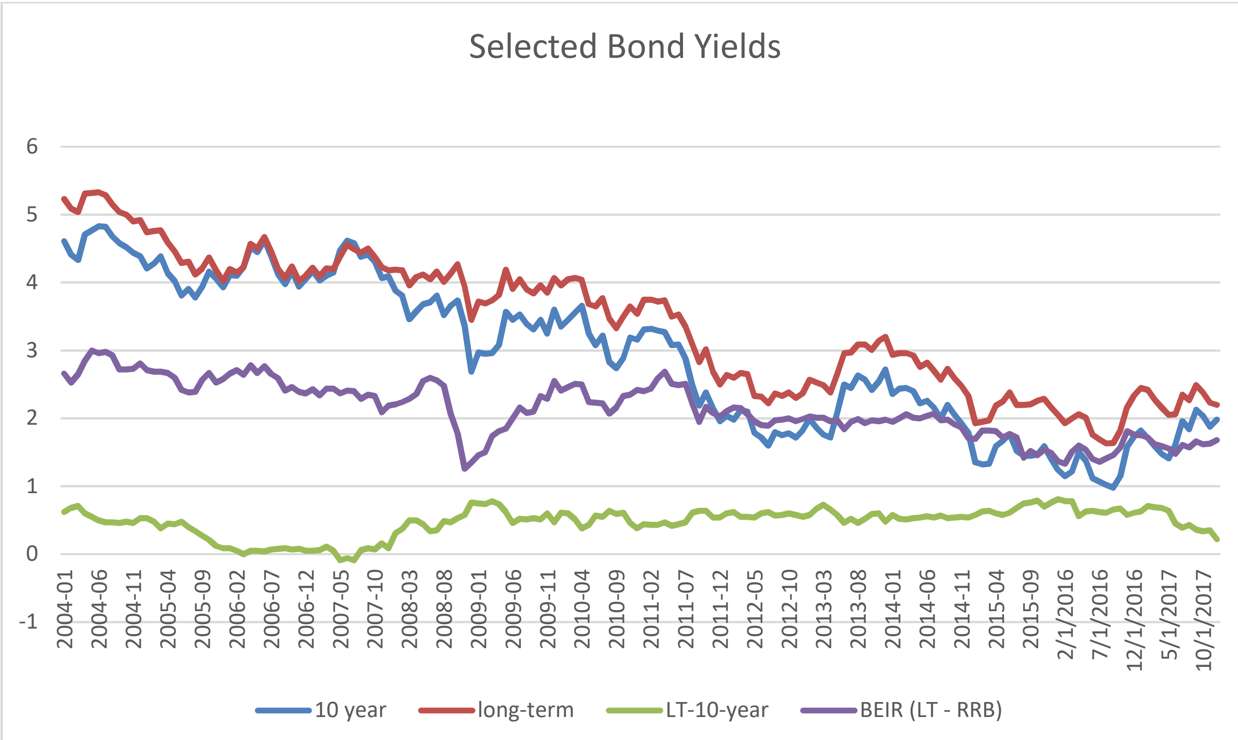
2.1.4 Interest Rate Levels

Interest rates in Canada have remained low over the past decade. Figure 3 shows 10-year and long-term bond yields in Canada over the last 14years, which have moved in tandem for the most part, with a correlation coefficient of 0.99 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.47% (0.53%) over the entire period. It is obvious from the graph that this spread increased during the last half of 2015, finally hitting a high of 0.81% in January of 2016. This spread declined steadily throughout 2017, hitting 0.22% in December 2017.[3] The graph also shows the break-even inflation rate (BEIR), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR can be viewed as an indicator of future inflation rates. This rate remained within the Bank's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.26% in November of 2008 around the peak of the crisis, and averaging 2.1% overall, slightly above the Bank's target. It sat at 1.68% at the end of 2017.

[3] This spread continued to decline through 2018 and sat at 0.02% as of September 12, 2018.

FIGURE 3

SELECTED BOND YIELDS – CANADA (2004-2017)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

The consensus view today is that bond yields will increase slowly in the coming months; although this is far from a given. This seems to be the consensus view of most economists in April of 2018, as can be seen in Table 5. The April 2018 Consensus Economics' Forecast for 10-year Canada bond yields was 2.7% for the end of April 2019 – up from the September 12, 2018 level of 2.32%. I say that such an increase is "far from a given" based on the fact that the Consensus Economics' forecasts for 10-year yields have consistently been well above the subsequent resulting actual 10-year yields since 2011, over-estimating the yield by more than 2% in 2012 and 2015, and by more than 3% for 2016. Finally, it is worth noting that as of September 12, 2018 the spread between 10-year Canada yields of 2.32% and 30-year Canada yields of 2.34% was a mere 0.02%, well below the long-term average spread between the two rates of 0.5% noted previously.

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2018-19)

10-Year Canada Yields	**July-18**	**April-19**
Conf. Board of Canada	2.4	2.7
CIBC World Markets	2.4	2.4
IHS Markit	NA	NA
Citigroup	2.3	2.8
BMO Capital Markets	2.3	2.7
Desjardins	2.4	2.8
Econ Intell Unit	NA	NA
Oxford Economics	2.3	2.9
EconoMap	2.2	2.7
JP Morgan	NA	NA
National Bank	2.5	2.8
RBC	2.4	3.0
TD Bank	2.4	2.6
University of Toronto	2.4	3.1
Scotia Bank	2.3	2.6
Informetrica	2.3	2.9
Stokes Econ Consulting	NA	NA
Inst Fiscal Studies	2.5	2.7
Capital Economics	2.4	2.0
Average	**2.4**	**2.7**
Median	**2.4**	**2.7**
Max	**2.5**	**3.1**
Min	**2.2**	**2.0**

Source: Consensus Economics Inc. (April 2018).

2.2 The Newfoundland and Labrador Economy

Table 6 provides forecasts of real GDP growth for Newfoundland and Labrador (NL) for 2018 and 2019. The private sector average forecasts (which includes the six big banks and the Conference Board of Canada) are for 0.3% real GDP growth in 2018 (with a maximum of 1.5% and a minimum of -2.0%), and 2.2 percent in 2019 (with a maximum of +3.4% and a minimum of 0.5%). The Department of Finance forecasts a decline of 0.8 percent in 2018, followed by growth of 1.1 percent in 2019. So there is general agreement that the economic growth will be negligible for NL in 2018 and will be moderately positive in 2019.

TABLE 6

NEWFOUNDLAND AND LABRADOR REAL GDP GROWTH FORECASTS (%) - 2018-19

		2018	**2019**
CIBC World Markets	22-Mar	-0.9	1.5
Scotiabank Group	3-May	0.5	1.4
TD Economics	15-Mar	1.5	1.7
BMO Nesbitt Burns	11-May	0.0	0.5
Royal Bank of Canada	12-Mar	-2.0	3.4
National Bank	1-May	1.5	3.5
Conference Board of Canada	8-May	1.4	3.3
Private Sector Average		**0.3**	**2.2**
Department of Finance	7-Mar	**-0.8**	**1.1**

Forecasts as of May 11, 2018

Source: http://www.economics.gov.nl.ca/frcstGDP.asp, September 14, 2018.

As the Conference Board of Canada (CB) notes in its fall provincial outlook, the NL economy has been hit by a number of factors: major projects passing their peak investment levels; mature offshore oil fields producing less oil; low oil prices; and, low commodity prices. Combined with a weak outlook for oil and commodity prices, the CB expects production and investment levels to continue to be weak.

The CB expects that oil production will remain flat over the next two years, and that oil prices will bounce back in the later part of 2016 and through 2017-18. In contrast, they expect commodity prices to remain low throughout 2016-18. This will lead to slightly negative metal production over the next two years, when combined with project life-cycle factors (e.g., iron ore production at Elross Lake and Labrador Trough peaking this year and declining going forward). One positive factor in metal production, is nickel production as Vale's Voisey's Bay mine enters phase two. This will have a positive impact on manufacturing. Combining this with the expected positive impact of a strong U.S. economy and a weak Canadian dollar, leads the CB to conclude that manufacturing will remain one of the bright spots for the NL economy in 2016-17.

The CB predicts that while business investment levels will remain higher than they were a few years ago, they will decline from their peak of over $8 billion in 2014, and lie around $6 billion in 2016 and 2017, before leveling off at just above $5 billion during 2018-20. While work continues on Muskrat Falls and Hebron oil developments, other projects have been delayed such as the West White Rose extension project, and the Alderon Iron Ore mine projects associated with transmission and development. Residential real estate investment will be hampered by slow economic growth and weaknesses in the labour market, and will also decline.

All of these factors have led to an overall weakened economy and labour market at the start of 2016. Table 7 shows that the CB forecasts that this will lead to real GDP growth declining by -0.8% in 2016, with the unemployment rate peaking at 13.1% over the 2015-20 period. This 2016 GDP growth estimate is slightly below the average estimate of the big five banks provided in Table 6, which is -0.68%. The CB estimates that recovery will occur during the latter part of 2016, and that real GDP growth will be slightly positive (at +0.2%) in 2017, with the unemployment rate declining to 12.4%. Beyond 2017, the CB predicts that the unemployment rate will fall below 12% and decline steadily to around 11% by 2020 on the back of 2018-20 real GDP growth rates of +1.4%, +7.0% and -1.6% respectively. Finally, it is interesting to note that the CB expects the contribution to NL GDP from the utilities sector to remain positive in 2016-17 (+0.4% and +0.6% respectively), and also in the ensuing three years (+0.8%, +1.3%, and +5.9% respectively). This is consistent with the low risk nature of utilities such as Newfoundland Power, whose demand is less cyclical than most industries.

TABLE 7

CONFERENCE BOARD OF CANADA ECONOMIC FORECASTS FOR NL - 2015-2020

	NEWFOUNDLAND AND LABRADOR FORECASTS					
Growth (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Real GDP	-0.2	-0.8	0.2	1.4	7.0	-1.6
CPI	0.7	4.6	2.2	2.1	2.3	2
Household Disposable Income	4.1	1.7	2.1	2.7	2.6	1.6
Employment	-0.9	-0.6	-0.4	-0.5	0.1	-0.9
Unemployment Rate	12.7	13.1	12.4	11.9	11.4	11.1
Utilities Sector GDP Contribution	9.9	0.4	0.6	0.8	1.3	5.9

3. CAPITAL STRUCTURE CONSIDERATIONS

3.1 Background

As previously noted, on page 17 of Order No. P.U. 13 (2013), the Newfoundland and Labrador Board of Commissioners of Public Utilities (hereafter the Board) stated:

> *"The Board notes that it has been some time since Newfoundland Power's capital structure has been comprehensively reviewed and that it may be appropriate for this issue to be addressed in Newfoundland Power's next general rate application."*

I begin my discussion with a review of the risk assessment of Newfoundland Power (NP) in previous hearings. In Order No. P.U. 19 (2003), the Board stated (on page 33) that they did "not anticipate a change in the business risk of NP in the foreseeable future and concurs with the assessment of NP and the cost of capital experts that NP is of average business risk compared to other utilities." On page 30, the Board noted that NP stated "All experts agreed that Newfoundland Power has an approximately average utility risk." The Order also notes (on page 32) an October 2002 report by S&P confirming an "A" rating for NP's first mortgage bonds, wherein S&P noted:

> *"Newfoundland Power's relatively low risk profile is supported by cost of service/rate of return regulation; the ability to flow through all power costs; a weather normalization mechanism; and no exposure to cyclical industrial consumers, which are serviced directly by the provincial government-owned utility, Newfoundland and Labrador Hydro."*

Recent debt rating reports (as provided in Exhibit 4 of NP's evidence) suggest that DBRS and Moody's continue to share S&P's 2002 opinion that NP possesses low business risk.

In similar fashion, the Board concluded that NP continued to be an average risk Canadian utility on page 13 of Order No. P.U. 43 (2009). On page 12 of this 2009 Order the Board noted that:

> *"The evidence shows that Newfoundland Power operates in a low risk environment. It is accepted that the regulatory regime is supportive with a range of mechanisms in place to mitigate risk…"*

The Board also noted on page 12 that Mr. Cicchetti suggested NP "operates in a low risk market under supportive regulation," and that he had characterized the regulatory regime under which NP operates as "exceptional."

Once again, on page 17 of Order No. P.U. 13 (2013), the Board suggested that at that time, they considered that "Newfoundland Power continues to be an average risk Canadian utility." The Board noted on page 14 of this Order that "Newfoundland Power argues that it continues to be an average risk Canadian utility," while the Consumer Advocate argued that NP was "at most, of average business risk and lower financial risk compared to other Canadian utilities."

The last quote in the paragraph above refers to both business and financial risk, where business risk includes an assessment of regulatory risk. The combination of business risk and financial risk determines a firm's total risk. This point is commonly accepted by expert witnesses, regulators, and by the debt rating agencies which make their overall risk (and rating) assessment by giving significant weight to both business and financial risk. In similar fashion, I will consider business risk, including regulatory considerations, then financial risk, and then discuss resulting conclusions regarding NP's capital structure.

3.2 Business Risk

The Board noted on page 11 of Order No. P.U. 43 (2009) the following summary of NP's risk position according to the Consumer Advocate (Transcript, October 14, 2009, page 25/11-20):

> *"Newfoundland Power has been and will continue to be a very well protected, stable, predictable, conservative, low risk utility operating in a very supportive regulatory environment where the company enjoys moderate, yet fairly steady customer growth, free from significant competition. With only a small amount of generation, Newfoundland Power is predominantly poles and wires. In essence, it is very low risk."*

This is an excellent summary of NP's operating environment and its resulting business risk, and is consistent with the views expressed by debt rating agencies. Hence, it seems reasonable to consider that NP continues to possess low business risk (which is consistent with the views of the debt rating agencies), unless compelling and material evidence demonstrates that NP's operating or regulatory environment has changed materially since 2013, or as far back as 2003 for that matter. My analysis below leads to me to conclude that such material changes have not taken place. Further, I provide empirical evidence which confirms *quantitatively* - what has generally always been agreed upon by NP, expert witnesses, and the Board, based on extensive *qualitative* analysis – NP is a low business risk utility.

3.2.1 Regulatory Risk

Newfoundland Power operates in an extremely supportive regulatory environment, which represents a big strength in terms of minimizing its business risk. This is reflected in evidence provided in previous decisions, and by the evidence provided by Mr. Coyne, who rates the Newfoundland regulatory environment among the top four in Canada. This point is also front and centre in credit rating reports for NP, both past and present. For example, the August 21, 2015 DBRS Rating Report lists a "stable and supportive regulatory environment" as the #1 strength among its "Rating Considerations." DBRS notes the effectiveness of the following mechanisms that are in place to smooth out the effects of various expenses and events: weather normalization reserve (WNR); rate stabilization account (RSA); demand management incentive account (DMIA); and, the pension expense variance deferral account (PEVDA). They conclude that NP operates in a regulatory framework that "allows Newfoundland Power to recover all prudently spent operating expenses and earn a reasonable return." I will verify the validity of this statement quantitatively later in my evidence.

In its January 19, 2015 Credit Opinion Moody's echoed the sentiment of DBRS, citing a "supportive regulatory and business environment" as one of three "Rating Drivers." In support of their conclusion, Moody's notes the pass through mechanisms mentioned by DBRS above and also notes that they consider the Public Utility Board (PUB) to be "supportive with a track record of reasonably timely and balanced decisions that enable NPI to generate stable cash flow and earn its allowed ROE and are not directly subject to political considerations." They also note that the "PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis." Once again, I will provide empirical evidence later in this report to support the validity of these statements regarding NP's cash flow stability and their consistency in earning profits.[4]

3.2.2 Operating Environment

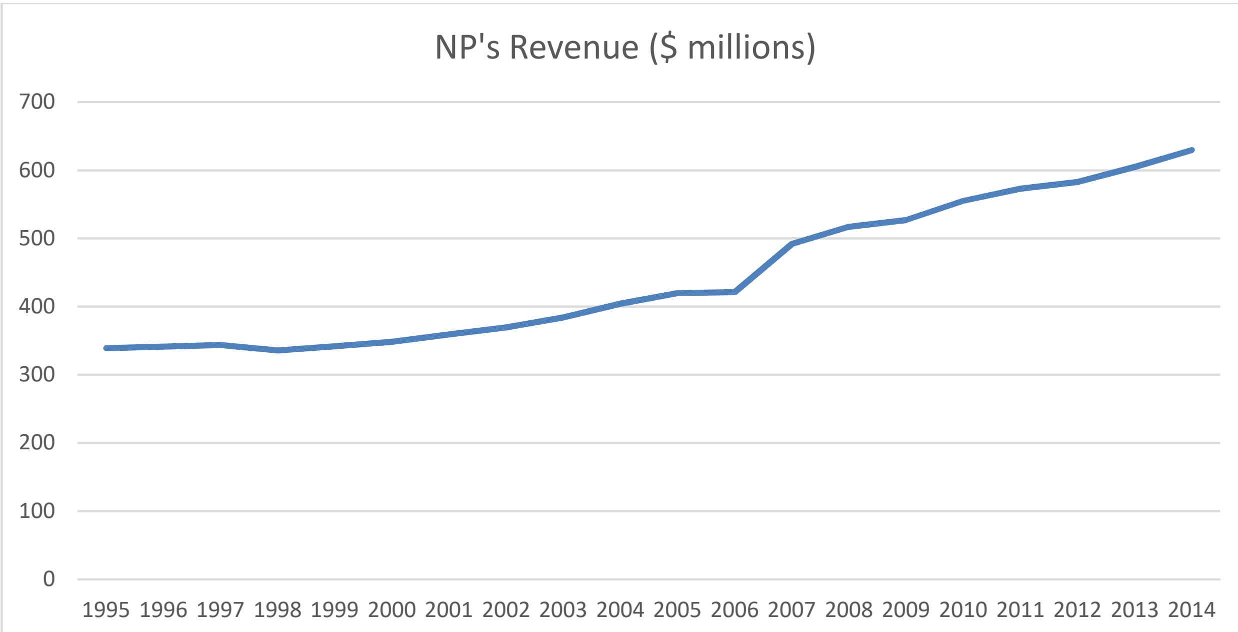
NP operates a virtual monopoly in a low business risk environment. As a result, revenue growth has been slow but steady, as one would expect for a company operating in a mature market with virtually no competition. Figure 4 verifies this steady growth in NP's revenue for the years 1995-2014. Annual revenue

[4] For example, Table 1 in the response to information request CA-NP-019 shows that NP has earned an ROE above the allowed ROE in 19 straight years, averaging 49.5 basis points above the allowed ROE.

growth averaged 3.38% over this period, and growth was only negative in one year, 1998, when revenue declined 2.31%.

FIGURE 4

NP REVENUE (1995-2014)



* Data Source: Newfoundland Power's annual reports, 1996 to 2014.

Certainly the economic forecast for Newfoundland and Labrador is not encouraging for the next two to three years. For example, as noted in Section 2, the Conference Board of Canada has forecasted negative Real GDP growth of -0.8% in 2016, followed by a slight rebound to +0.2% in 2017 and to +1.4% in 2018. However, NP has survived previous declines in economic activity and their sales and operating income continued to grow steadily. While the forecast economic decline is not a positive development, fortunately for NP it is less affected than companies operating in cyclical industries such as real estate or consumer durables. Further, given its low-risk business model accompanied with strong regulatory support, there is no obvious reason that a weak economy represents a significant increase in permanent business risk for NP. Indeed, the historical record confirms that NP has weathered previous economic "storms" and managed to maintain growth in sales and operating income, and earn ROEs at or above the allowed ROEs. For example, Figure 5 plots the annual growth rate in NP revenue versus the real GDP growth rate for Newfoundland

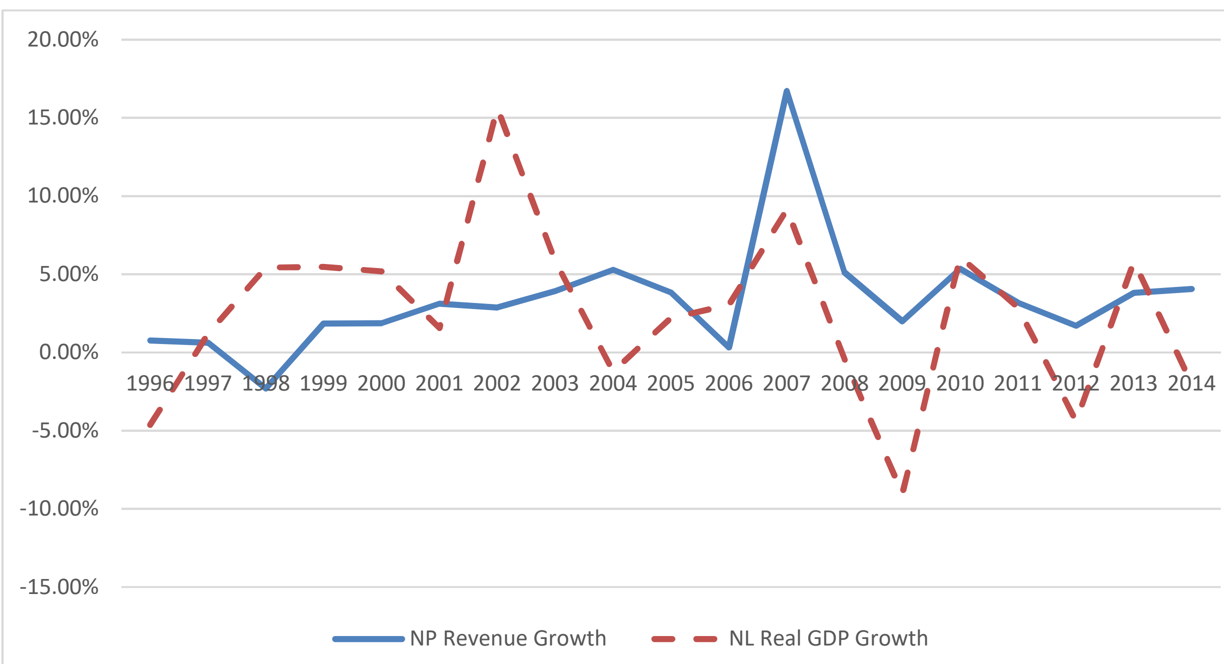
and Labrador over the same period. As noted previously, NP experienced only one decline in revenue growth over this period, and grew in all six of the years when the real GDP growth rate was negative.

Over this period, the average annual growth rate in NP's sales was 3.4%, versus 2.5% for real GDP growth, but the volatility of NP's sales growth was much lower, as measured by its standard deviation of 2.9% versus 5.6% for NL's real GDP growth. Further, the correlation coefficient between NP's sales growth rates and real GDP growth rates over this period was positive as expected, but low at 0.27 - reflecting the fact that NP's sales are more resilient than NL's real GDP growth rates. In other words, while the Newfoundland and Labrador economic forecast is not a positive, the evidence suggests that NP can be expected to weather this economic decline, just as it has in the past.

FIGURE 5

NP REVENUE ANNUAL GROWTH VERSUS

NL REAL GDP GROWTH (%) - 1995-2014



* Data Source: Newfoundland Power's annual reports, 1996 to 2014, and CANSIM database.

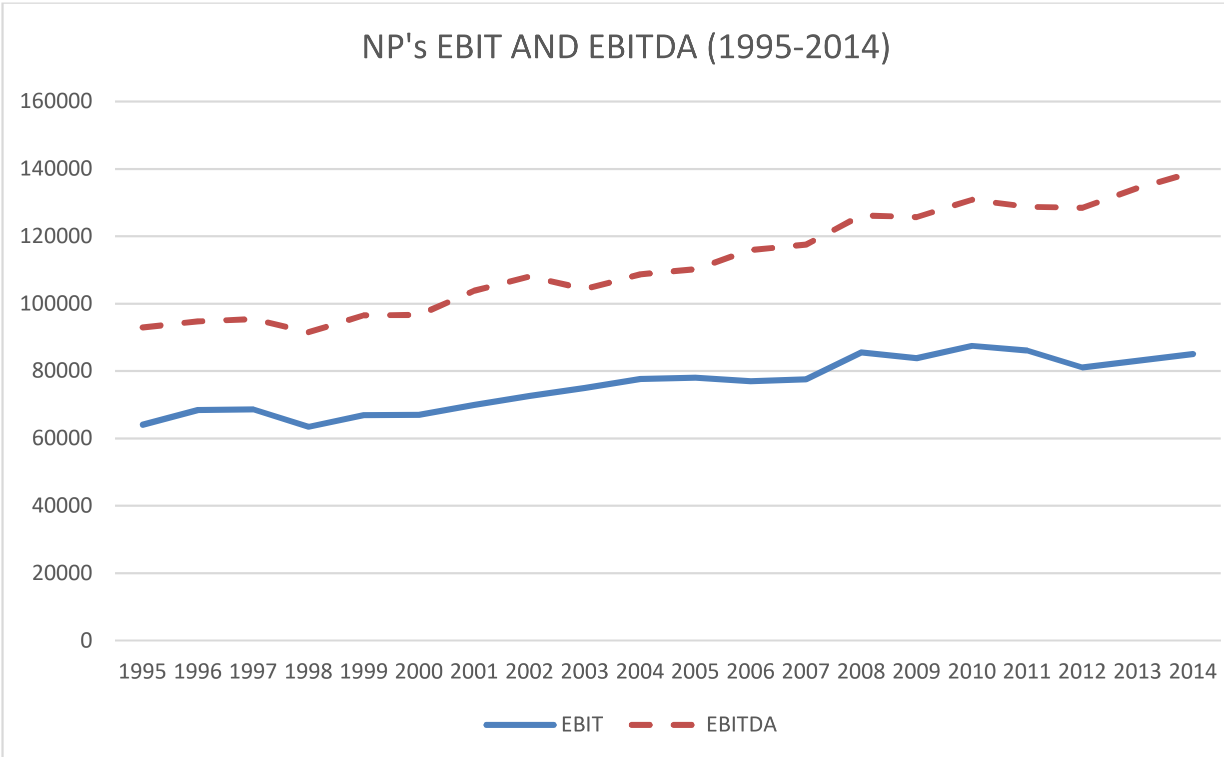
NP serves as a low-risk distributor, with almost all of their energy generation needs provided by Newfoundland and Labrador Hydro (NLH). As mentioned above, since capital expenditures and long-term debt issues are reviewed and approved by the PUB, the risk of cost disallowances is very low. The RSA, WNR, DMIA and PEVDA all serve to minimize variance in operating income related to supply costs, the impact of abnormal weather conditions, as well as other costs to NP. Hence NP faces very little risk that it will not be able to pass legitimate expenses on to customers and earn an adequate rate of return in such a supportive regulatory and business framework.

The points above are consistent with the beliefs expressed in previous hearings and with those expressed by rating agencies. For example, in its January 19, 2015 Credit Opinion, Moody's notes NP's "low-risk business model" as the # 1 rating consideration. Moody's notes that NP is "effectively protected from potential competition," and that sales have grown "at a relatively low and predictable rate of 1-2% annually," and that "growth has not taxed NPI either operationally or financially due to the relatively timely recovery of capital and operating costs." In other words, NP has low business risk because it is operating a virtual monopoly with revenue growing slowly but steadily where it is able to pass reasonably incurred costs onto consumers due to various pass through mechanisms.

It is not surprising that when we combine all of these factors with the stable growth in revenue documented previously, that we also find that NP displayed slow but steady growth in operating income over the 1995-2014 period as proxied by either EBIT or EBITDA, with EBIT (EBITDA) growing at an average annual rate of 2.2% (1.6%). The steady growth of EBIT and EBITDA displayed in Figure 6 is similar to that portrayed for revenue in Figure 4. All of the empirical observations evident in Figures 4 to 6 are consistent with a company that has low business risk. Not surprisingly, NP has been able to earn its allowed ROE or higher for 19 consecutive years.

FIGURE 6

NP'S EBIT AND EBITDA (1995-2014)



* Data Source: Newfoundland Power's annual reports, 1996 to 2014.

3.2.3 Other Considerations Raised by Mr. Coyne

On page 15 of Appendix A: Capital Structure of his evidence, Mr. Coyne states that the Muskrat Falls supply system will lead to increased "potential weather-related risk to Newfoundland Power's electricity supply." As noted in CA-NP-175, this contradicts assertions made by NLH in response to CA-NLH-115 (for the Board's Outage Inquiry) where it states that "the reliability of supply to customers will be improved." Mr. Coyne acknowledges in his response to CA-NP-175 that there is no evidence to support his claim in Appendix A, since the matter is currently being studied. As a result, there appears to be no concrete evidence to suggest that Muskrat Falls has led to an increase (or decrease) in NP's business risk.

While I do not claim to be an expert on weather patterns, I have not read any compelling evidence that suggests severe weather events are more likely to occur in 2016-17 than they have in the past. It is also difficult to see why this creates so much additional business risk for NP than it does for other Canadian utilities who are also subject to similar risks. Similarly, many U.S. utilities operate in environments where severe hurricanes and/or flooding are as likely to occur as are extreme weather events in Newfoundland

and Labrador. Of course, we all hope that such events will not happen, but they have occurred in the past, and given the supportive mechanisms in place and the support of the PUB, NP has always managed to maintain their profitability. In light of this lack of supporting evidence, I disagree with the notion that such events lead to higher business risk for NP.

Finally, Mr. Coyne suggests that NP faces greater business risk because of its size. First of all, NP has always been small relative to some, but not all, other utilities, so this does not seem to warrant attention as something that has changed since the last hearings to affect NP's business risk. Secondly, NP operates in a mature segmented market with virtually no competition and with a proven business and regulatory model that allows it to steadily grow its revenue base and pass through its costs to maintain earnings and cash flow stability. In other words, there is no reason to believe that a small firm operating a virtual monopoly in such a supportive environment is any riskier than a big firm operating in markets where there is more competition, or where they face greater regulatory risk, for example. Finally, there is no evidence that its small size has hindered NP from accessing public (or private) debt markets, as attested to by its successful long-term bond issue in 2015, and its existing short-term credit facility that is available to it.

In summary, none of the concerns expressed by Mr. Coyne in this sub-section affect my previous conclusion that NP has low business risk, which is consistent with the views expressed by rating agencies.

3.2.4 A Quantitative Assessment of NP's Business Risk

My examination of NP's operating and regulatory environment above suggests that NP possesses low business risk. The same can likely be said for most other regulated utilities, especially those that are distributors and that operate virtual monopolies in supportive regulatory environments. Certainly, it is easy to see that regulated utilities such as NP have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great an ability to pass through increases in their costs to their customers. As noted in Section 3.2.1 there has been general agreement in previous hearings that NP is an average risk regulated Canadian utility. Finally, rating reports consistently suggest that NP and most other regulated Canadian utilities have low business risk.

Most experts assessing "business risk" would agree that it refers to some variation of factors that cause uncertainty, or volatility, in operating income. For example, the 2013 CFA curriculum (Reading 38, page 82) states: "**Business risk** is the risk associated with operating earnings. Operating earnings are risky because total revenues are risky, as are the costs of producing revenues."

In this section, I use three variations of a commonly used measure of operating income volatility, the coefficient of variation of EBIT (hereafter CV-EBIT), to *quantify* a firm's level of business risk. The CV is determined by dividing the standard deviation (SD) of EBIT by the expected or average EBIT level. The rationale for using the CV as a measure of EBIT volatility rather than simply using the SD of EBIT, is that the SD is affected by the size of EBIT. In other words, firms with larger EBITs will have higher SDs of EBIT, even if they have less volatility, simply because the level of the EBIT figures used to determine the SD are much higher. The CV is more appropriate in such instances and is commonly used to measure volatility since it effectively "scales" the SD of EBIT when it is divided by the expected or average level of EBIT.

I use the three variations of CV-EBIT described below:

(1) **CV(EBIT)** is calculated as the standard deviation of EBIT for a given utility over my sample period (1995-2014) divided by the expected EBIT next year (which is determined by multiplying the most recent EBIT figure times one plus the median growth rate in EBIT for that firm).

(2) **CV(EBIT)-5 year** is calculated as the average of 5-year "rolling" estimates of CV(EBIT) using the standard deviation of EBIT over the previous five years divided by the average EBIT over the previous five years. I then take the average of these five-year CV(EBIT) estimates for each firm.

(3) **CV (EBIT/Sales)** is calculated as the standard deviation of the EBIT/Sales ratio (1995-2014) divided by the average of the EBIT/Sales ratio over this period.

Measure (1) uses expected EBIT as the denominator in determining the CV of EBIT, which is one common approach used to estimate CV-EBIT, as in Petty et al (2011) for example.[5] Notice that this approach estimates the standard deviation using all available EBIT observations. Measure (2) is another commonly used approach which uses the average EBIT as the denominator, as in the 2013 CFA curriculum (Reading 28, page 351). However, as discussed previously EBIT has continued to grow steadily for NP and also for the other utilities I use for comparison purposes. This implies that using a long-term average that will by nature be well below current EBIT levels may be inappropriate. I adjust for this by estimating the CV-EBIT using data for every year with available data using the most recent five year period. I then take the average of these rolling annual CV(EBIT) estimates for each company. Finally, measure (3) uses the EBIT/Sales

[5] Source: Financial Management: Principles and Applications, 6th edition, by J. William Petty, Sheridan Titman, Arthur J. Keown, Peter Martin, John D. Martin, Michael Burrow, Hoa Nguyen, 2011, Pearson Higher Education.

ratio rather than the level of EBIT. This is a valid measure of business risk, since it measures volatility in the operating profit margins for firms. It also has the advantage that, as a ratio, the expected value and past average values will often coincide since these profitability margins often tend to gravitate to some long-term average. This makes it unnecessary to make the adjustments required to determine the CV-EBIT estimates as in (1) or (2) above.

Figure 7 depicts a summary of the main results of this analysis. The evidence clearly shows that U.S. utilities have much higher volatility in EBIT according to all three measures of CV-EBIT, relative to the Canadian comparable group, and relative to NP. We also see NP displays much lower business risk than the U.S. firms, and also slightly lower business risk than its Canadian peers. This leads to the conclusion that NP is very low business risk – confirming empirically, the conclusions made above in my qualitative assessment of NP's business risk. The EBIT/Sales chart in Figure 7 demonstrates that the average and median EBIT/Sales ratios are similar for the U.S. firms, the Canadian group, and NP. So, in essence, Canadian utilities, including NP, generate similar operating profit margins to U.S. utilities, but with much, much less volatility in operating income. This of course, suggests U.S. utilities have much higher business risk, which has often been argued in previous Canadian hearings.

FIGURE 7

COEFFICIENT OF VARIATION OF EBIT ESTIMATES (1995-2014)

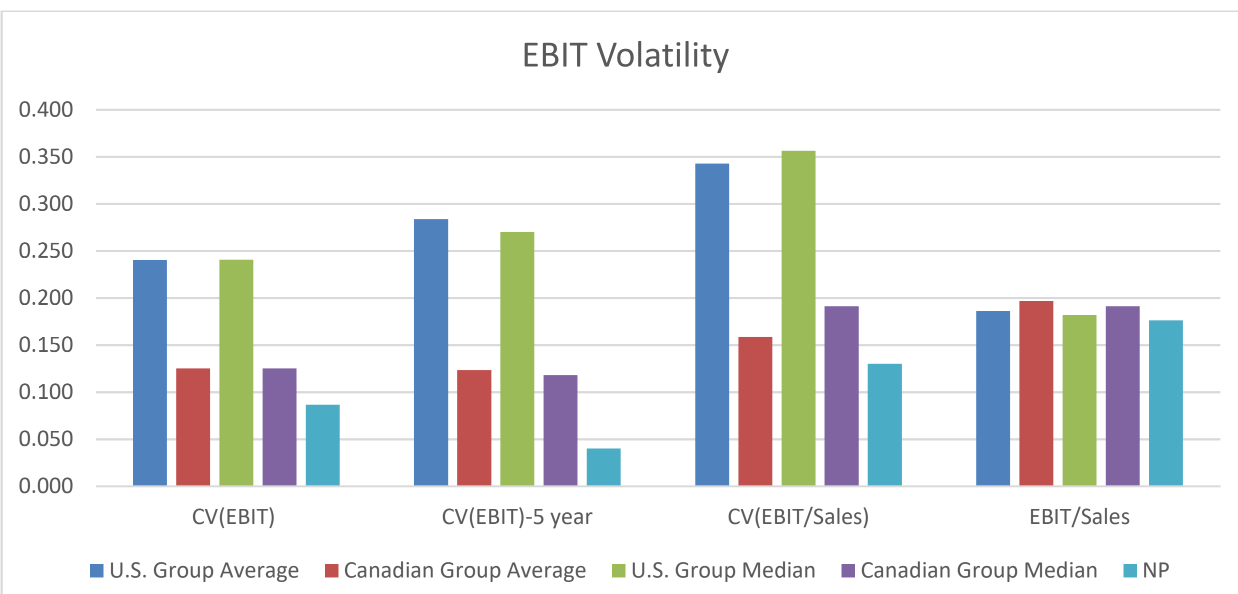


Table 8 confirms that the patterns displayed in Figure 7 are not driven by the use of averages or medians, as it reports the results for all U.S. and Canadian firms used in the comparison groups. Table 8 clearly shows that all three CV-EBIT measures are higher for each U.S. utility than for NP – much, much higher in most cases. This also true when the U.S. CV-EBIT measures are compared to the other Canadian firms, with the exception of the last two measures for NSTAR which are lower than one or two Canadian firms respectively (but not NP). Again, these results confirm that NP has very low business risk, as do the other Canadian regulated utilities examined.

TABLE 8

COEFFICIENT OF VARIATION OF EBIT ESTIMATES FOR ALL FIRMS (1995-2014)

		Coefficient of Variation of EBIT Measures (1995-2014)			
U.S. Firms		**CV(EBIT)**	**CV(EBIT)-5 year**	**CV(EBIT/Sales)**	**EBIT/Sales**
	Allette inc.	0.300	0.298	0.206	0.182
	Duke Energy Inc.	0.241	0.395	0.459	0.193
	Great Plains Energy	0.252	0.270	0.357	0.180
	OGE Energy	0.218	0.148	0.422	0.152
	Pinaccle West Corp.	0.161	0.167	0.261	0.222
	Westar Energy	0.333	0.580	0.545	0.204
	NSTAR*	0.176	0.128	0.151	0.170
	U.S. Group Average	**0.240**	**0.284**	**0.343**	**0.186**
Canadian Firms					
	NSPI	0.121	0.118	0.231	0.257
	Enbridge Gas	0.129	0.115	0.191	0.191
	Gaz Metro**	0.125	0.137	0.054	0.142
	Canadian Group Average	**0.125**	**0.124**	**0.159**	**0.197**
Newfoundland Power	**NP**	**0.087**	**0.040**	**0.130**	**0.176**
	U.S. Group Median	0.241	0.270	0.357	0.182
	Canadian Group Median	0.125	0.118	0.191	0.191

NOTES: U.S. data was obtained from the Compustat database. Canadian data was obtained from annual reports 1995-2014 for Newfoundland Power, Enbridge Gas Distribution Inc., Emera (for NSPI), and from 2009-2015 for Valener (for Gaz Metro).

* Data only available to 2011. Subsidiary of Eversource.
** Data only available 2009-2015.

Finally, while U.S. regulated utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Canadian counterparts, including NP. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts – although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions. However, the higher business risk displayed by U.S. utilities is completely consistent with the observation that U.S. utilities have higher betas than Canadian ones, as noted in Figure 12 of Mr. Coyne's evidence for example. Higher betas indicate higher investment (i.e., total) risk. Since U.S. utilities have higher allowed ROEs and equity ratios, on average, it is reasonable to conclude that the higher betas may be attributed to the higher business risk faced by U.S. utilities.

In fact, it is possible to estimate the "unlevered" beta for a company, which is the beta after adjusting for the firm's level of financial leverage. This is commonly viewed as the beta on the firm's underlying assets or operations. Intuitively, the unlevered beta will be related to business risk. I will illustrate using Mr. Coyne's evidence for U.S. and Canadian betas of 0.70 and 0.64 respectively, for example.[6] I will then combine these beta estimates with the implied debt-equity (D/E) ratios using the debt-to-capitalization ratios of 0.52 and 0.65 respectively for U.S. and Canadian utilities as provided by Mr. Coyne in Appendix A, Exhibit JMC-2. These imply D/E ratios of 1.08 and 1.86 for U.S. and Canadian utilities, respectively. Using the commonly used equation to determine unlevered betas (i.e., where B(unlevered) = B(levered)/(1 + D/E)), we can then see that the implied "unlevered" betas for Canadian and U.S. utilities are 0.22 and 0.34 respectively. This also implies lower business risk for Canadian utilities, consistent with the evidence provided above for the CV-EBIT measures.

3.2.5 Concluding Remarks Regarding Business Risk

[6] I use these estimates **for illustrative purposes only**, since they illustrate the "relative" relationship between U.S. and Canadian utility betas – i.e., U.S. utility betas are higher. For the record, both betas appear unreasonably high to me. This is at least partially due to the use of "adjusted" betas, which adjust for betas tendency to gravitate to one. This adjustment does not make sense for utility betas, which are not likely to gravitate to a level anywhere nearly as high as one, since they are much less risky than the average company trading in the market.

The qualitative analysis above confirms that NP continues to be a low business risk electric distribution utility operating in a very supportive regulatory environment, similar to the conclusions reached by the Board in previous decisions, and also consistent with the analyses of credit rating agencies of NP. My quantitative analysis provides strong support for these qualitative conclusions, as NP is shown to display much lower volatility in operating income than comparable U.S. firms, and slightly below Canadian comparable utilities. As such, I conclude that NP continues to be a very low business risk firm.

3.3 Financial Risk

In this section, I examine the financial risk of NP by reference to a(n):

(1) comparison of allowed ROEs and equity ratios with other Canadian utilities;

(2) comparison of NP's credit metrics to other Canadian utilities; and,

(3) examination of the effect on NP's credit metrics of changes in allowed ROEs and equity ratios from the existing base case.

My analysis concludes that NP has lower financial risk than its Canadian counterparts on average, and that there is definite room for the Board to decrease the allowed equity ratio, without affecting NP's ability to access credit on reasonable terms.

3.3.1 Allowed ROEs and Equity Ratios

Tables 9 and 10 provide data on allowable ROEs and equity ratios for Canadian electric and gas distributors from 2011 to 2015. The data is taken from the 2013, 2014 and 2015 Concentric reports that were provided in response to CA-NP-157. I have no reason to dispute the integrity of the data and have verified from other sources the 2015 data, which is the primary focus of my discussion.

TABLE 9

ALLOWED ROES (%) - 2011-2015

	2011	**2012**	**2013**	**2014**	**2015**
Canadian Electric Distributors					

ATCO Electric Ltd.	8.75	8.75	8.30	8.30	8.30
ENMAX Power Corp.	8.75	8.75	8.30	8.30	8.30
EPCOR Distribution Inc.	8.75	8.75	8.30	8.30	8.30
FortisAlberta Inc.	8.75	8.75	8.30	8.30	8.30
FortisBC Inc.	9.90	9.90	9.15	9.15	9.15
Hydro-Quebec Distribution	7.32	6.37	6.19	8.20	8.20
Maritime Electric Company Limited	9.75	9.75	9.75	9.75	9.75
Nova Scotia Power Inc.	9.35	9.20	9.00	9.00	9.00
Ontario's Electric Distributors	9.58	9.12	8.98	9.36	9.30
Saskatchewan Power Corp.	7.40	7.40	8.50	8.50	8.50
Average	**8.83**	**8.67**	**8.48**	**8.72**	**8.71**
Median	**8.75**	**8.75**	**8.40**	**8.40**	**8.40**
Canadian Gas Distributors					
AltaGas Utilities Inc.	8.75	8.75	8.30	8.30	8.30
ATCO Gas	8.75	8.75	8.30	8.30	8.30
Enbridge Gas Distribution Inc.	8.39	8.39	8.93	9.36	9.30
FortisBC Energy Inc.	9.50	9.50	8.75	8.75	8.75
Gaz Metro Limited Partnership	9.09	8.90	8.90	8.90	8.90
SaskEnergy Inc.	8.75	8.75	8.75	8.75	7.74
Union Gas Limited	8.54	8.54	8.93	8.93	8.93
Average	**8.82**	**8.80**	**8.69**	**8.76**	**8.60**
Median	**8.75**	**8.75**	**8.75**	**8.75**	**8.75**
<u>Including All Firms in Both Groups</u>					
Average	**8.83**	**8.72**	**8.57**	**8.73**	**8.67**
Median	**8.75**	**8.75**	**8.75**	**8.75**	**8.50**
Newfoundland Power	**8.38**	**8.80**	**8.80**	**8.80**	**8.80**

Table 9 shows that NP has provided an allowable ROE over this period that is slightly above the average and/or median levels for other Canadian distributors. For example, with a 2015 allowable ROE of 8.8%, NP is slightly above the average (median) for Canadian gas distributors of 8.60% (8.75%), and also slightly above the figures for Canadian electric distributors of 8.71% (8.40%). If we aggregate the data for both types of distributors NP's allowed ROE is slightly above the average of 8.67% and the median of 8.50%. In other words, NP's allowed ROE is close to the average for Canadian distribution utilities. With respect to the equity ratios provided in Table 10, we can see that NP's equity ratio of 45% is well above the mean and medians in the 38-40% range for each group, and for both groups combined. In fact, 45% is

3% higher than the next highest equity ratio, and 10 of the 17 utilities listed in this table have equity ratios of 40% or lower.

TABLE 10

EQUITY RATIOS (%) - 2011-2015

	2011	2012	2013	2014	2015
Canadian Electric Distributors					
ATCO Electric Ltd.	39.00	39.00	38.00	38.00	38.00
ENMAX Power Corp.	41.00	41.00	40.00	40.00	40.00
EPCOR Distribution Inc.	41.00	41.00	40.00	40.00	40.00
FortisAlberta Inc.	41.00	41.00	40.00	40.00	40.00
FortisBC Inc.	40.00	40.00	40.00	40.00	40.00
Hydro-Quebec Distribution	35.00	35.00	35.00	35.00	35.00
Maritime Electric Company Limited	42.70	41.70	43.50	43.10	41.90
Nova Scotia Power Inc.	40.00	37.50	37.50	37.50	37.50
Ontario's Electric Distributors	40.00	40.00	40.00	40.00	40.00
Saskatchewan Power Corp.	40.00	40.00	40.00	40.00	40.00
Average	**39.97**	**39.62**	**39.40**	**39.36**	**39.24**
Median	**40.00**	**40.00**	**40.00**	**40.00**	**40.00**
Canadian Gas Distributors					
AltaGas Utilities Inc.	43.00	43.00	42.00	42.00	42.00
ATCO Gas	39.00	39.00	38.00	38.00	38.00
Enbridge Gas Distribution Inc.	36.00	36.00	36.00	36.00	36.00
FortisBC Energy Inc.	40.00	40.00	38.50	38.50	38.50
Gaz Metro Limited Partnership	38.50	38.50	38.50	38.50	38.50
SaskEnergy Inc.	37.00	37.00	37.00	37.00	37.00
Union Gas Limited	36.00	36.00	36.00	36.00	36.00
Average	**38.50**	**38.50**	**38.00**	**38.00**	**38.00**
Median	**38.50**	**38.50**	**38.00**	**38.00**	**38.00**
Including All Firms in Both Groups					
Average	**39.36**	**39.16**	**38.82**	**38.80**	**38.73**
Median	**40.00**	**40.00**	**38.50**	**38.50**	**38.50**
Newfoundland Power	**45.00**	**45.00**	**45.00**	**45.00**	**45.00**

The analysis above shows that NP has lower financial risk than the average Canadian distributor based solely on allowed ROEs and equity ratios. While NP's allowed ROE is very close to the average, the allowed equity ratio is much, much higher, indicating lower financial risk, all else being equal. It is worthy of note at this time that this lower financial risk does not seem warranted due to higher business risk for NP versus similar Canadian utilities based on the discussion in the previous section – recall that the analysis in that section concluded that NP had average-to-slightly below average business risk when compared to other Canadian utilities, and much less than U.S. utilities.

3.3.2 Credit Metric Comparisons

In this section, I compare the credit metrics of NP to those for some comparable Canadian utilities. Unfortunately, due to variances in size, ownership structure and the availability of public information such as debt rating reports, and/or financial statement information, the sample size is limited. Table 11 provides the statistics for the three main ratios used by DBRS that were obtained from the most recent DBRS reports that I was able to find.[7] Using the ratios as calculated by one source should enhance the consistency in the calculation of such ratios.

TABLE 11

DEBT RATINGS AND CREDIT METRICS - 2014

	DBRS RATINGS AND CREDIT METRICS			
	Issuer Rating	**Total Debt to Capital**	**CF/Debt**	**EBIT Interest Coverage**
Canadian Regulated Utilities				
1. CU Inc.	A (high)	60.20%	12.60%	2.67
2. Enbridge Gas Distribution Inc.	A	55.70%	16.40%	2.60
3. FortisAlberta Inc.	A (low)	56.70%	17.00%	2.18
4. FortisBC Inc.	A (low)	58.40%	14.10%	2.44
5. Gaz Metro Limited Partnership	A	67.20%	15.70%	1.82
6. Nova Scotia Power Inc.	A (low)	61.20%	15.80%	2.19
Average		**60.88%**	**15.65%**	**2.16**
Median		**59.80%**	**15.75%**	**2.19**
Newfoundland Power (Aug 21, 2015 DBRS)				
2014	A	**55.30%**	**17.70%**	**3.06**

[7] The figures are for 2014 for all firms except for Enbridge Gas Distribution Inc., which are for 2013, and Metro Gaz which are for 2015.

Data obtained from DBRS Reports: 1. April 12, 2015; 2. March 12, 2014 - report 2013 figures; 3. December 16, 2015; 4. April 8, 2015; 5. December 21, 2015 (for Gaz Metro Inc., based on the guarantee of GMLP) – report 2015 figures; and, 6. February 18, 2015.

The results provided in Table 11 are consistent with what one would expect based on the discussion in the previous sub-section – namely, according to analysis of credit metrics provided by DBRS, NP appears to have lower financial risk than its Canadian counterparts. In particular, NP has a debt-to-capital ratio of 55% that is well below the group average or median of 60%, and is in fact below the ratio for all firms in the sample. Similarly, NP's interest coverage ratio of 3.06 for 2014 is well above the group average and median figures of 2.16 and 2.19 - it is also higher than the coverage ratio for each firm in the sample. NP's 2014 CF/Debt ratio of 17.7% is also higher than those for all of the other listed Canadian utilities.

NP's debt-to-capital ratio of 55% lies on the cut-off point between an A and AA rating for low business risk firms, according to DBRS criteria. The EBIT coverage ratio for NP is well above the 2.8 cut-off value for a AA assessment, while their CF/Debt ratio also slightly exceeds the 17.5% AA cut-off point. Therefore, it is not surprising their A rating was confirmed, since their metrics suggest they lie somewhere between the bottom half of the AA category and the top half of the A category, and even if they deteriorated somewhat they would be well in the "A range." The average debt-to-capital ratio for the other Canadian firms lies firmly in the middle of the A category (i.e., 55-65%). The interest coverage and CF/Debt ratios for the sample group also fall squarely in the A range, also consistent with their range of A(low) to A(high) ratings. It is noteworthy that NP has an A rating, falling in the middle of the range of ratings for the firms in this group, despite the fact that the group firms possess weaker credit metrics than NP. This also implies that even if NP's metrics were weaker they would probably maintain their A rating status, given their below-to-average business risk discussed previously.

3.3.3 Credit Metric Scenarios

In this section I evaluate the potential impact of various allowed ROE and equity ratio scenarios on the credit metrics of NP. I use the data provided in Exhibit 3 of NP's evidence to construct the base case for 2013-2017. I then estimate the primary credit metrics relied upon by DBRS and Moody's respectively. Finally, I provide forecasts of what would happen to these metrics under various assumptions regarding ROE and equity ratios, and discuss the implications. For ease of reference, Table 12 provides the ranges for the metrics used in assessing utilities' financial risk by Moody's and DBRS (for low business risk firms – which is what DBRS uses in assessing utilities such as NP).

TABLE 12

CREDIT METRIC CRITERIA

Moody's Metrics	**A**	**Baa**
(CFO pre-WC + Interest)/Interest	4.5 to 6.0	3 to 4.5
CFO pre-WC/Debt	19 to 27%	11 to 19%
(CFO pre-WC - Dividends) /Debt	15 to 23%	7 to 15%
Debt/Capitalization	40 to 50%	50 to 59%

		(Low Bus. Risk)	
DBRS Metrics	**AA**	**A**	**BBB**
Cash flow to debt	above 17.5%	12.5 to 17.5%	10.0 to 12.5%
Debt to Capital	below 55%	55 to 65%	65-75%
EBIT to Interest	Above 2.8	1.8 to 2.8	1.5 to 1.8

Table 13 presents the base case scenario using the data provided in Exhibit 3 by NP, based on existing rates and equity ratios. The data shows that from 2013 to 2017, under existing rates and according to NP's own data, that NP's metrics remain solid and lie at the high Baa to low A range for Moody's, and lie at the high A to low AA range according to DBRS metrics. In addition, their interest coverage remains well above 2.0, never falling below 2.36. In other words, NP's metrics continue to look strong for 2015-2017 at existing rates, using NP's own data, and assuming no changes in the equity ratio.

TABLE 13

CREDIT METRIC ESTIMATES – 2013-2017

Base Case

Moody's Metrics	**2013**	**2014**	**2015E**	**2016E**	**2017E**	**NP**
(CFO pre-WC + Interest)/Interest	3.61	3.65	3.77	3.90	3.78	Baa(mid-high)
CFO pre-WC/Debt	18.75%	18.40%	18.01%	18.20%	17.43%	Baa(high)
(CFO pre-WC - Dividends) /Debt	14.14%	13.95%	16.20%	14.88%	15.41%	Baa(high) to A(low)
Debt/Capitalization	54.07%	54.51%	54.45%	54.12%	54.15%	Baa(mid)

DBRS Metrics - calculated						
Cash flow to debt	18.75%	18.40%	18.01%	18.20%	17.43%	A(high) to AA(low)
Debt to Capital	54.34%	54.85%	54.72%	54.38%	54.39%	AA(low)
EBIT to Interest	2.48	2.52	2.57	2.49	2.36	A(high)

The discussion with respect to business risk in Section 3.2 concluded that NP is a below-average-to-average business risk Canadian utility. The comparison of NP's allowed ROEs and equity ratios and its recent credit metrics to other Canadian utilities showed that NP has lower financial risk. This implies that the Board should consider a decrease in NP's equity ratio to bring it in line with Canadian averages. Of course, such changes would affect NP's credit metrics, so it is worth examining the extent of such. Similarly, as allowed ROEs provided by regulators have been declining in recent years in response to lower interest rate levels among other things, it is also of interest to examine what credit metrics would result from considering alternative ROEs. With this in mind, I have prepared an analysis of projected credit metrics under various ROE scenarios (i.e., 7.5%, 8.0%, 8.3%, 8.5% and 8.8%) first using the existing equity ratio of 45%, and then using a 40% equity ratio. The results using a 45% equity ratio are presented in Table 14.

TABLE 14

2016-17 CREDIT METRIC ESTIMATES USING A 45% EQUITY RATIO

	USING 45% Equity Ratio					
2016 Metrics	**ROE**	**ROE**	**ROE**	**ROE**	**ROE**	
	7.50%	**8.00%**	**8.30%**	**8.50%**	**8.80%**	**NP**
Moody's Metrics						
(CFO pre-WC + Interest)/Interest	3.89	3.96	4.00	4.02	4.06	Baa(high)
CFO pre-WC/Debt	18.19%	18.60%	18.85%	19.01%	19.26%	Baa(high) to A(low)
(CFO pre-WC - Dividends) /Debt	14.87%	15.28%	15.53%	15.69%	15.94%	Baa(high) to A(low)
Debt/Capitalization	54.12%	54.12%	54.12%	54.12%	54.12%	Baa(mid)
DBRS Metrics						
Cash flow to debt	18.19%	18.60%	18.85%	19.01%	19.26%	AA(low)
Debt to Capital	54.38%	54.38%	54.38%	54.38%	54.38%	AA(low)
EBIT to Interest	2.40	2.49	2.55	2.64	2.64	A(high)
2017 Metrics	**ROE**	**ROE**	**ROE**	**ROE**	**ROE**	
	7.50%	**8.00%**	**8.30%**	**8.50%**	**8.80%**	
Moody's Metrics						**NP**
(CFO pre-WC + Interest)/Interest	3.88	3.95	3.99	4.01	4.05	Baa(high)
CFO pre-WC/Debt	18.04%	18.45%	18.70%	18.86%	19.11%	Baa(high) to A(low)

(CFO pre-WC - Dividends) /Debt	16.02%	16.43%	16.68%	16.84%	17.09%	A(low)
Debt/Capitalization	54.15%	54.15%	54.15%	54.15%	54.15%	Baa(mid)
DBRS Metrics						
Cash flow to debt	18.04%	18.45%	18.70%	18.86%	19.11%	AA(low)
Debt to Capital	54.39%	54.39%	54.39%	54.39%	54.39%	AA(low)
EBIT to Interest	2.41	2.51	2.56	2.60	2.66	A(high)

Table 14 shows that for 2016 and 2017, using the current 45% equity ratio, and under various ROE scenarios and according to NP's own data, that NP's metrics would remain solid and lie at the high Baa to low A range for Moody's, and lie at the high A to low AA range according to DBRS metrics. In addition, NP's interest coverage remains well above 2.0, never falling below 2.4. This is true under all of the allowed ROE figures. This suggests that the PUB could lower the ROE significantly at the current allowed equity ratio and the credit metrics would remain strong.

Since the focus of my discussion is on the allowable equity ratio, I will now proceed to see how reducing it would impact credit metrics. Table 15 examines the credit metric estimates using a 40% equity ratio. As in Tables 13 and 14, I use the financial statement data provided in Exhibit 3 by NP to construct the estimates. The main assumptions that I make are that: (1) the marginal tax rates for 2016 and 2017 would be those implied in Exhibit 3 of NP's data; (2) depreciation would equal the estimates provided in Exhibit 3; (3) the items "excluding net income" that are used to estimate the CFO pre-WC estimates provided in Exhibit 3 would remain unchanged, so that CFO pre-WC can be recalculated by adjusting for changes in the net income figure only; (4) common equity would remain at the same dollar levels reported in Exhibit 3; (5) common equity will earn the allowed ROE resulting in the appropriate figure for net earnings available to common shareholders; and, (6) new long-term debt would be issued at 4.45% (i.e., the yield on the September 2015 NP bond issue) and used to bring the equity ratio down to 40%, with the additional interest expense being added to the interest expense estimates for 2016 and 2017 provided in Exhibit 3 of NP's evidence.

TABLE 15

2016-17 CREDIT METRIC ESTIMATES USING A 40% EQUITY RATIO

2016 Metrics	**ROE 7.50%**	**ROE 8.00%**	**ROE 8.30%**	**ROE 8.50%**		**NP**
Moody's Metrics						

(CFO pre-WC + Interest)/Interest	3.50	3.56	3.59	3.62	Baa(mid)
CFO pre-WC/Debt	14.91%	15.25%	15.45%	15.59%	Baa(high)
(CFO pre-WC - Dividends) /Debt	12.19%	12.53%	12.73%	12.87%	Baa(high)
Debt/Capitalization	59.00%	59.00%	59.00%	59.00%	Baa(low)
DBRS Metrics					
Cash flow to debt	14.91%	15.25%	15.45%	15.59%	A(high)
Debt to Capital	59.24%	59.24%	59.24%	59.24%	A(mid)
EBIT to Interest	2.21	2.29	2.34	2.37	A(mid) to A(high)
2017 Metrics	**ROE 7.50%**	**ROE 8.00%**	**ROE 8.30%**	**ROE 8.50%**	
Moody's Metrics					**NP**
(CFO pre-WC + Interest)/Interest	3.49	3.55	3.58	3.61	Baa(mid)
CFO pre-WC/Debt	14.78%	15.12%	15.32%	15.46%	Baa(high)
(CFO pre-WC - Dividends) /Debt	13.13%	13.46%	13.67%	13.80%	Baa(high)
Debt/Capitalization	59.04%	59.04%	59.04%	59.04%	Baa(low)
DBRS Metrics					
Cash flow to debt	14.78%	15.12%	15.32%	15.46%	A(high)
Debt to Capital	59.28%	59.28%	59.28%	59.28%	A(mid)
EBIT to Interest	2.22	2.30	2.35	2.38	A(mid) to A(high)

Table 15 shows that if the equity ratio was reduced to 40%, NP's credit metrics for 2016 and 2017 would remain firmly in the Baa range for Moody's, and in the mid-to-high A range for DBRS, if the allowed ROE is also reduced. Similarly, the interest coverage ratio remains well above 2, and never falls below 2.2, under any scenario presented. In other words, NP's credit metrics would remain solid if the PUB reduced NP's allowable equity ratio to 40% and also reduced the allowed ROE.

3.3.4 Concluding Remarks Regarding Financial Risk

The discussion in Section 3.3.1 shows that NP has lower financial risk than other Canadian utilities based upon a combination of an allowable ROE which is about average and equity ratios which are much higher than average. Given this attractive ROE to equity ratio combination, it is not surprising that NP displays superior credit metric ratios to its Canadian peers, as discussed in Section 3.3.2. An examination of credit metric sensitivity to changes in allowed ROEs and equity ratios indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and the allowable ROE was also reduced.

3.4 Capital Structure Recommendation

Both the qualitative discussion and quantitative analysis in Section 3.2 show clearly that NP has low business risk, similar or slightly lower than that for similar Canadian firms. Sections 3.3.1 and 3.3.2 demonstrate that NP currently has less financial risk than other Canadian utilities based on an examination of allowable ROEs and equity ratios, and of existing credit metrics. Finally, the examination of NP's credit metric sensitivity in Section 3.3.3 indicates that NP would maintain solid metrics if the equity ratio was reduced to 40% and if the allowed ROE was also reduced.

It is not clear why a low business risk firm like NP requires an equity ratio that is much higher than average, while being allowed to earn an ROE that is around average. I recommend that the Board reduce NP's equity ratio to 40%, which would bring it in line with Canadian averages. The additional "above average" 5-6% equity thickness is not warranted based on NP's business risk, nor is it required to maintain solid credit metrics that will permit NP to maintain its ability to raise credit on reasonable terms.

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N-M4-EDA-5-Attachment

Exhibit 8 (Continued)

Market Cap Decile	Market Cap of Largest Company (in thousands)	Size Premium
8	682,750	2.51
9	422,811	2.80
10	206,795	6.10
	Breakdown of the 10th Decile	
10a	206,795	4.34%
10b	128,672	9.81

Source: SBBI Valuation Yearbook (2012), pp. 86–90.

Thus, ignoring any appropriate specific-company premium, an estimate of the required return on equity is 3.00% + 4.20% + 4.34% = 11.54%. A caution is that the size premium for the smallest decile (and especially the 10b component) may reflect not only the premium for healthy small-cap companies but also former large-cap companies that are in financial distress. If that is the case, the historical estimate may not be applicable without a downward adjustment for estimating the required return for a small but financially healthy private company.

A so-called modified CAPM formulation would seek to capture departures from average systematic risk. For example, if the analyst estimated that the company would have a beta of 1.2 if publicly traded, based on its publicly traded peer group, the required return estimate would be

Risk-free rate + Beta × Equity risk premium + Size premium,

or 3.00% + 1.2 × 4.20% + 4.34% = 12.38%. This result could be reconciled to a simple build-up estimate by including a differential return of (1.2 − 1.0)(4.20%) = 0.84% in the specific-company premium.

4.3.2 *Bond Yield Plus Risk Premium*

For companies with publicly traded debt, the **bond yield plus risk premium method** provides a quick estimate of the cost of equity. The estimate is

$$\text{BYPRP cost of equity} = \text{YTM on the company's long-term debt} + \text{Risk premium} \quad (13)$$

The YTM on the company's long-term debt includes

- a real interest rate and a premium for expected inflation, which are also factors embodied in a government bond yield; and
- a default risk premium.

The default risk premium captures factors such as profitability, the sensitivity of profitability to the business cycle, and leverage (operating and financial) that also affect the returns to equity. The risk premium in Equation 13 is the premium that compensates for the additional risk of the equity issue compared with the debt issue (recognizing that debt has a prior claim on the cash flows of the company). In US markets, the typical risk premium added is 3%–4%, based on experience.

EXAMPLE 9

The Cost of Equity of Vodafone from Two Perspectives

You are valuing the stock of Vodafone Group Plc as of early 2019, and you have gathered the following information:

UK gilt 30-year yield	1.70%
Vodafone Group Plc 7.875% 02/15/2030	4.64%

The Vodafone bonds, you note, are rated BBB+ by Standard & Poor's and Baa2 by Moody's Investors Service. The beta on Vodafone's stock is 0.70. As a matter of judgment, you have decided to use a risk premium of 3% in the bond yield plus risk premium approach.

1 Calculate the cost of equity using the CAPM. Assume that the equity risk premium is 5.20%.

2 Estimate the cost of equity using the bond yield plus risk premium approach, with a risk premium of 3.0%.

3 Suppose you found that Vodafone's stock, which closed at £140.52 on 8 April 2019, was slightly undervalued based on a DCF valuation using the CAPM cost of equity from Question 1. Does the alternative estimate of the cost of equity from Question 2 support the conclusion based on Question 1?

Solution to 1:

1.70% + 0.70(5.20%) = 5.34%.

Solution to 2:

Add 3.0% to the Vodafone bond YTM: 4.64% + 3.0% = 7.64%. Note that the difference between the Vodafone bond YTM and the long gilt YTM is 2.94%. This amount plus 3.0% is the total estimated risk premium versus UK treasury debt, 2.94% + 3.0% = 5.94%.

Solution to 3:

Not necessarily; *undervalued* means that the value of a security is greater than market price. All else equal, the lower the discount rate, the higher the estimate of value. The inverse relationship between discount rate and value, holding all else constant, is a basic relationship in valuation. If Vodafone appears to be undervalued using the CAPM cost of equity estimate of 5.34%, that does not necessarily mean it will also appear to be undervalued using a 7.64% cost of equity based on the bond yield plus risk premium method.

The bond yield plus risk premium method can be viewed as a build-up method applying to companies with publicly traded debt. The estimate provided can be a useful check when the explanatory power of more-rigorous models is low. Given that a company's shares have positive systematic risk, the yield on its long-term debt is revealing as a check on cost of equity estimate. For example, the 8.375% bonds of Koninklijke KPN N.V. due 1 October 2030 (rated BBB by Standard & Poor's and Baa3 by Moody's) were priced to yield 5.2% as of early April 2019, so an estimated required return for its stock not greater than 5.20% would be suspect.