Appendix B

EVIDENCE OF MR. JAMES COYNE
CONCENTRIC ENERGY ADVISORS INC.
REGARDING THE COST OF CAPITAL ESTIMATION

PREPARED DIRECT TESTIMONY:
JAMES M. COYNE

PREPARED FOR:
FORTISBC ENERGY INC.

BEFORE THE:
BRITISH COLUMBIA UTILITIES COMMISSION

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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 the FortisBC Energy Inc. ("FEI", or the "Company"), a wholly-owned subsidiary of Fortis Inc.

I am among Concentric's professionals who provide expert testimony before U.S. federal, state and Canadian national 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 utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, demand side management, low-income programs, fuels and power markets. I have testified or provided expert evidence in over 30 proceedings in state, provincial and federal jurisdictions in Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions, and staff.

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. In collaboration with the Canadian Gas and Canadian Electric Associations, I also publish a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. I have been an invited speaker for several CAMPUT events including the recent 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, Director in DRI's 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 A.

B. Scope of Testimony

I have been asked to provide an estimate of the cost of capital for FortisBC Energy Inc. ("FEI"), for the purpose of establishing the return on equity ("ROE") and capital structure to go into effect, January 1, 2016. In order to estimate the cost of capital, I have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. I have also reviewed past decisions of the British Columbia Utilities Commission ("BCUC") in consideration of such matters. The analysis provided in this report will support my overall recommendation on the cost of equity and capital structure. That analysis includes the following:

1) examination of the legal and regulatory requirements for determination of a fair rate of return;
2) examination of the regulatory, institutional, economic and financial conditions in Canada and the U.S.;
3) determination of Canadian and U.S. proxy groups with companies comparable to FEI with respect to business and financial risks;

4) examination of the business and financial risks of FEI relative to the Canadian and U.S. proxy group companies to determine whether it is reasonable to rely on those respective proxy groups to estimate the required ROE for FEI;
5) estimation of the cost of equity using the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) methods;
6) development of a range of results for the Canadian and U.S. proxy groups;
7) estimation of FEI's cost of common equity based on application and interpretation of that range and the business and financial risks of FEI relative to the respective proxy groups;
8) a survey of authorized returns in other jurisdictions;
9) assessment of FEI's operating and financial profile, and a conclusion with respect to the appropriateness of its capital structure; and
10) assessment of whether an automatic adjustment mechanism should be adopted for subsequent rate years.

Executive Summary

The following summarizes the regulatory standards and analysis I have relied upon to reach my conclusions and recommendations.

1) Established legal and regulatory principles require that FEI be given an opportunity to earn a fair return on its invested capital.
2) In order for the rate of return to be judged fair, the company must be provided with a reasonable opportunity to earn a return that meets three requirements:
    a. Comparable investment standard;
    b. Financial integrity standard; and
    c. Capital attraction standard.

    These standards must be met individually and in total in order to satisfy a fair return.

3) I have estimated the cost of equity for FEI utilizing both the CAPM and DCF 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 Table 1.

4) Risk Factors - In addition to the analytical models, I have developed a detailed assessment of the risks of the Canadian and U.S. proxy group companies with respect to business and financial risk characteristics. I cite evidence that Canadian and U.S. financial markets are integrated, and government and regulatory policies are similar from an investor's perspective. The following summarizes the conclusions of my risk analysis.

- Investment Risk – More than ever, Canada and the United States are similar from an investment perspective. Specifically, it is reasonable to conclude that investors would not find material differences in the macroeconomic and financial market conditions between Canada and the U.S. that would cause them to assign a different risk profile to Canadian and U.S. companies that are otherwise comparable.
- Proxy Groups - It is appropriate to consider Canadian and carefully chosen U.S. proxy groups as benchmarks for natural gas distribution utilities, such as FEI. More specifically, given the small number of publicly-traded, Canadian utilities, it is appropriate to consider the analytical results for a group of similar-risk U.S. gas distribution companies.
- Business Risk – Both Canadian and U.S. regulators have provided the operating companies in the proxy groups with cost recovery and revenue stabilization mechanisms that mitigate many of the important business risks, such as gas supply, fluctuations in volume/demand, capital investment costs, and operating costs that tend to fluctuate significantly from year to year. Longer term, the highly integrated North American natural gas supply network assures comparable supply dynamics, although these can vary by region in both Canada and the US. Common energy and environmental policy drivers have forged a close alliance between the countries at the federal level, notwithstanding projects such as Keystone XL which have occasionally pitted regional and national interests. The Western Climate Initiative is a prime

example of common interests in energy and environmental policy, expressed through the combined actions of Canadian provinces (including BC) and U.S. states designed to track and manage greenhouse gas emissions. From an investor perspective, the business risks for a utility in Canada are similar to those in the U.S.

- Financial Risk – FEI and the Canadian proxy group companies have substantially more financial leverage in their capital structures and weaker credit metrics than the U.S. proxy group companies. This may indicate that credit rating agencies are satisfied with the degree of regulatory protection and cash flow protection for debt investors, but these metrics expose equity investors to greater risk than their U.S. counterparts. As such, FEI has greater financial risk than the U.S. proxy group.

5) Recommended ROE - As seen in Table 1, the results from the alternative models cover a range from 8.89% (U.S. Multi-Stage DCF) to 12.70% (Canadian, Constant Growth DCF). Within this range, an equal weighting of all methods with both Canadian and U.S. proxy groups would produce an average of 10.04% but one must give consideration to the appropriate weights placed on each method and proxy group. Consistent with the Hope decision, it is the end result and not the method that is determinative of a fair return.

Table 1: Summary of Results (including 50 bps flotation costs)

	Canadian Utility Proxy Group	U.S. Gas Distribution Proxy Group	Average
CAPM	9.08%	10.08%	**9.58%**
Constant Growth DCF	12.70%	9.68%	**11.19%**
Multi-Stage DCF	9.82%	8.89%	**9.36%**
Average	**10.54%**	**9.55%**	**10.04%**

The evidence indicates that a carefully selected group of U.S. proxy companies is more like FEI than the Canadian proxy companies due to their business profiles, but because of the importance of a Canadian perspective, I have given them equal weight in my recommendation. The U.S. proxy group is based on a careful screening of the universe of U.S. companies to select those most comparable to FEI. That screening process considers factors such as credit ratings, payment of dividends, availability of growth rate estimates, and the extent to which the company is engaged in regulated natural gas distribution operations. Importantly, the credit ratings for the U.S. gas distribution proxy group are between BBB+ and A+, similar to FEI's rating of A3 from Moody's (equivalent to Standard and Poor's A-). By choosing U.S. proxy group companies with similar credit ratings to FEI, the proxy group is comprised of similar-risk utilities with comparable business and financial risks, as indicated by those credit ratings.

Turning to the choice of models, I understand the BCUC has placed varying weights on the DCF and CAPM. In its 2009 Terasen Gas decision, the Commission gave the most weight to the DCF approach, and lesser to the ERP and CAPM approaches.[1] In the 2013 GCOC Decision, the Commission placed equal weight on the DCF and CAPM.[2] I similarly have placed equal weight on the DCF and CAPM model as the basis for the recommended ROE for FEI.

Based on the results of the analyses discussed above and throughout my testimony, I have reconciled for current market conditions in my selection of inputs to the CAPM analysis to address concerns with the ability of the CAPM model to produce reasonable results in light of the factors affecting the inputs at this time. Bond yields in Canada and the U.S. have been driven to all-time lows, and most would agree below sustainable levels in the longer term. Utility betas have also been impacted, and market risk premium estimates cover a broad spectrum. There is a substantial gap between historic market risk premiums and the higher risk premiums implied in current stock market data. These are problems with the CAPM, and in general, in the current market environment.

As described in the CAPM section, I have attempted to reconcile for these market conditions. I begin with a forecast Canadian risk free rate. The Market Risk Premium I have employed is a combination of both Canadian and U.S. market inputs, including both

1 Terasen Gas Inc., Return on Equity and Capital Structure, Decision, December 16, 2009, at p. 65.
2 Generic Cost of Capital Proceeding, Decision, May 10, 2013, at p. 80.

historic and forward looking estimates. The betas derived from the U.S. and Canadian proxy groups are adjusted for the market mean, consistent with academic literature and common practice by both providers and users of such data.

In determining the appropriate weight to be placed on the DCF and CAPM models, with the CAPM inputs I have described, I believe that equal weight is reasonable. In determining the relative weight placed on the DCF constant growth vs. multi-stage models, I have considered the Commission's finding in the 2013 GCOC decision, where it found:

> The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.[3]

Utilizing only the multi-stage DCF and the CAPM results for both Canadian and U.S. proxy groups reduces the average to 9.47%. I believe the range produced from the overall average of all models, 10.04%, and that produced by these 4 models, 9.47%, represents an appropriate estimate of FEI's cost of equity, with 9.5% being the lowest reasonable estimate. It is also corroborated by my risk premium analysis, and considers the results of an "alternative CAPM" analysis which includes a beta adjusted to an industry mean. In consideration of the alternative CAPM result, I have focused on an ROE estimate at the lower end of the reasonable range. I therefore conclude that a cost of equity for FEI of 9.5 percent on 40 percent equity, as discussed in the capital structure section of the testimony, is a fair return.

[3] Ibid, at p. 70.

II. 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.[4]

The United States law regarding fair return for utility cost of capital has evolved similarly. The U.S. 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 become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

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

[4] *Northwestern* at p. 186.

> dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

With the passage of time, the "Fair Return Standard" has been interpreted many times in both Canada and the U.S. The National Energy Board ("NEB") 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.

> The Board 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 Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[5]

All three standards must be met and none ranks in priority to the others. A discussion of the legal requirements for satisfying the Fair Return Standard in Canada was articulated by the Ontario Energy Board ('OEB") in its 2009 Order deciding the Generic Cost of Capital for its Ontario transmission and distribution utilities:

> The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal.

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

> Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[6]
>
> ***
>
> … all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].[7]

The BCUC embraces the same legal standards for the application of the Fair Return Standard as those put forth by the NEB, the OEB and those established through Canadian and U.S. common law. The BCUC recognizes as part of the regulatory compact that a regulated utility has the opportunity to earn a return on its invested capital in exchange for safe, reliable and non-discriminatory service to its ratepayers, at cost based rates.[8] The BCUC also recognized that the approach to determining a fair return on the cost of invested capital must satisfy the Fair Return Standard and that "the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."[9] Further, the Commission recognizes that it "does not consider the rate impacts of the revenue required to yield the fair return;" and that customer needs will be met by "seeking an optimal capital structure and the opportunity cost of capital."[10]

The assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in like-risked enterprises. Investors must consider whether there might be alternative investment opportunities that would provide a better

[6] Ontario Energy Board, EB-2009-084, Report of the Board on the cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at p. i.
[7] Ibid, at p. 19.
[8] BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at p. 6.
[9] Ibid at p. 12.
[10] Ibid.

return for the same risk. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to settle on a price that provides investors with a return that is adequate for the risks involved. Thus, for any given level of risk, there is a corresponding level of return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return. In addition to setting the return at the "opportunity cost" of capital, a fair return must also be sufficient to maintain the financial integrity of the utility which requires a return sufficient to maintain credit metrics such that the utility can maintain a favorable bond rating to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. Finally, the return must be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The Stand-Alone Principle provides that the utility must 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 its recent Generic Cost of Capital Decision, the BCUC reaffirmed its adherence to the Stand-Alone Principle. The Commission stated:

> The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a "new" utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.[11]

[11] Ibid, at p. 100.

In order to establish a fair return, 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, satisfying the stand alone principle in doing so.

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. The Commission adheres to this principle in its 2013 Decision:

> The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, *i.e.*, the ROE and the common equity component, allowed to the utility.[12]

Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks of their shareholders. Consequently, when a regulator approves a deemed capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of the company is a function of both its business risk and its financial risk. Business risk refers to the political and regulatory environment that the company operates within and the operational and competitive forces that could potentially exert pressure on earnings. Financial risk refers to the extent of fixed obligations in the utility's capital structure and the extent to which those obligations must be met before utility common equity shareholders receive their returns. As fixed obligations increase, the required equity return increases to compensate investors. The fair return, therefore, depends on both the equity return and capital structure.

[12] GCOC Decision, May 10, 2013, at p. 12.

North American regulatory practice generally follows two alternative approaches to setting the capital structure and ROE: 1) the generic approach, and 2) setting ROE and capital structure based on individual proceeding. In Canada, the generic approach is common practice, but this approach is applied differently across the Canadian provinces. Some Canadian jurisdictions authorize a single equity return applicable to the generic or benchmark utility, and reflect differentiation in utility risk through a deemed equity ratio (*e.g.* Alberta[13] and Ontario[14]). Other Canadian jurisdictions provide a generic equity return, but differentiation in the utility risk profile may be reflected as either an adjustment to the utility's equity return, or an adjustment to its deemed capital structure, or both (British Columbia[15] and Quebec[16]). In the U.S., regulators most often determine the reasonableness of the utilities' capital structure allowed in rates based on that utility's risk profile relative to its proxy group, credit metrics, and specific circumstances.

III. BUSINESS AND ECONOMIC CONDITIONS IN CANADA AND THE U.S.

A. <u>Summary of Current Economic and Capital Market Conditions</u>

This section of my testimony describes the current business and economic conditions as well as the near term outlook for Canada and the U.S.

The global economy has become an increasingly interdependent set of relationships between countries. It is nearly impossible for a disruption in one major economy not to have a rippling effect throughout the global economy. Beginning with the Canadian

13 Alberta Utilities Commission, 2013 Generic Cost of Capital Decision, Decision 2191-D01-2015 (March 23, 2015) para. 416, at p. 84.

14 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084 (December 11, 2009) at 50, note that historically Ontario had provided ROE differentiation between its gas distributors but currently all distribution utilities are subject to the formulaic ROE produced by the AAM. Timing, however, may vary between utility rate plans, causing ROEs to differ among utilities. Currently, Union Gas earns an authorized ROE of 8.93% and Enbridge Gas Distribution earns 9.3%.

15 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 2) Decision (March 25, 2014).

16 The Régie has awarded different capital structures and returns on equity for Gazifére (9.10% on 40% equity, D-2013-102, R-3840-2013 Phases 1 and 2, July 12, 2013, at 14), Gaz Métro (8.9% on 38.5% equity, Decision D-2011-182, R-3752-2011, November 25, 2011), and Hydro Québec Distribution (8.2% on 35% equity D-2014-037, R-3854-2013,Phase 1, March 6, 2014).

outlook, the Bank of Canada (the "Bank" or the "BOC") finds that overall risk to financial stability in Canada has risen, but the resilience of the financial system continues to improve.[17] The Bank rates the key risks to the Canadian financial system to range from "moderate" to "elevated,"[18] and projects a modest pickup in global economic growth for 2015 and 2016, as investor confidence increases and consumers and businesses realize the benefits of recent deleveraging, accommodative monetary policy, low oil prices and financial repair.

Stimulative economic policies have exerted significant influence on keeping government bond yields very near all time lows. The Bank predicts that monetary policy will begin to normalize in advanced economies as the global recovery proceeds, and interest rates are projected to rise. Financial market volatility will begin to reflect two-sided interest rate risk. The Bank sees challenges to the global economic outlook arising from the repercussions of rising interest rates on emerging market economies, the significant challenges faced by the Chinese economy due to its sharp slow-down in economic growth, a real estate market correction and slower growth in investment spending; and the impact of low oil prices on the Canadian economy. Prolonged low oil prices in Canada will increase the vulnerability of the Canadian financial system to adverse shocks to employment and income.[19]

In Canada, ongoing reforms in the areas of G-20 priorities for 2015 pertaining to the capital, liquidity and leverage framework for banks, initiatives for making over-the-counter derivatives markets safer, and putting measures in place to help end "too big to fail", continue to strengthen the Canadian financial system. The Bank predicts that the U.S. economic recovery will continue to strengthen despite its weaker than expected start to the year, attributed to a harsh winter. The stalled growth in China and the euro area may serve as a drag on the Canadian economy, and indeed the first two quarters signal that Canada is in a technical recession. The Bank acknowledges that much of the world, including Canada and the U.S., continue to be highly dependent on stimulative monetary

[17] Bank of Canada, For Immediate Release, June 11, 2015: Bank of Canada says risk to financial stability is slightly higher, but system is more resilient.
[18] Bank of Canada, Financial System Review June 2015 at p. 3.
[19] Ibid at pp. 1-3.

conditions which have held interest rates near historic lows, and resulted in equity indexes near all-time highs, and volatility in financial markets. These stimulative monetary policies have caused certain vulnerabilities in the Canadian financial system.[20]

The Bank has identified three such system vulnerabilities which may pose risks for the Canadian economy: 1) the elevated level of household indebtedness; 2) imbalances in the housing market causing increases in housing prices; and 3) investor risk taking prompted by monetary stimulus incentives which could increase volatility in times of market stress.[21] The Bank goes on to identify the four key risks to the Canadian financial system: 1) the potential for a broad-based decline in employment and incomes of Canadians reducing the ability of highly-indebted households to service debts and triggering a sharp correction in the housing market (risk is considered "elevated"); 2) a sudden shift in market expectations about U.S. monetary policy which could lead to a possibility of sharply-higher long-term interest rates transmitted to Canada through its strong links to the global financial markets (risk is considered "moderate"); 3) the transmission of financial stress to the Canadian financial system from China and other emerging market economies through trade, commodity and financial channels (risk is considered "elevated"); and 4) a financial disruption in the euro area that may lead to global market volatility, a widespread repricing of risk and a flight to liquidity that would adversely impact Canadian markets (risk is considered "moderate").[22]

According to Consensus Economics, the Canadian economy is benefitting from the strong U.S. dollar and the U.S. economic recovery, but has not yet fully reflected the full impact of the decline in prices for crude oil, one of Canada's primary exports, posing a significant challenge to the Canadian economy in the near term.[23] Though low oil prices provide a benefit to Canadian consumers, it cannot make up for the negative impact low oil prices have on the Canadian oil industry. Weak oil prices and the weaker-than-expected U.S. recovery in the first quarter of 2015 led to a contraction in the Canadian economy in the beginning of 2015. However, the Bank projects the Canadian economy will continue to

20 Ibid.
21 Ibid at p. 2.
22 Ibid at pp. 2-3.
23 Consensus Forecasts Survey Data (January 12, 2015) at p. 17.

strengthen despite lower oil prices due to the anticipated strengthening of the U.S. economy and supportive financial conditions.[24]

The Bank of Canada recently announced that it would maintain the overnight rate target at ½ percent. The Bank noted that while core inflation was at approximately 2 percent, consumer energy prices have experienced a year over year decline, with CPI inflation near the bottom of the target range. The Bank attributes this in part to slack in the Canadian economy, despite the transitory effects of the depreciation of the Canadian dollar among other sector-specific factors. The Bank also notes that "the stimulative effects of previous monetary policy actions are working their way through the Canadian economy."[25] The Bank highlights the impact of the Canadian resource sector's adjustment to lower oil prices and the spill-over effects to the rest of the Canadian economy, noting that adjustments are complex and will take some time.[26] The Bank looks optimistically to the U.S. recovery and solid household spending in Canada, but uncertainty in China and other emerging market economies are raising questions about the pace of the global recovery, which contribute to low commodity prices and result in volatile financial markets.[27] Some movement in the Canadian dollar is helping to absorb some of the financial impact of low commodity prices and exchange rate-sensitive exports are gaining some momentum, though the broader export picture in Canada remains uncertain. Overall, the Bank decided that the risks to inflation remain at a level where the current stance of monetary policy continues to be appropriate.[28] Clearly, the Bank of Canada is still exercising the utmost of caution as it continues to pursue stimulative measures to counter the slack in the Canadian economic recovery.

The U.S. continues its economic recovery at a steady, but uneven pace. Based on recently revised data, U.S. GDP growth for Q1 2015 was 0.6%, and rebounded in Q2 2015 to an annual rate of 3.7%.[29] With consumer confidence reaching the highest point in the last

[24] Bank of Canada, Financial System Review June 2015 at p. 5.
[25] Bank of Canada, Press Release, September 9, 2015, Bank of Canada Maintains overnight rate target at ½ percent.
[26] Ibid.
[27] Ibid.
[28] Ibid.
[29] Blue Chip Economic Indicators, September 10, 2015 at p. 5.

five years, the U.S. economy is on track to continue its strengthening trend. U.S. consumer spending has benefitted from a drop in fuel prices, with the price of West Texas Intermediate now below $50/barrel.[30] Labor market conditions are tightening and there are signs of U.S. increases in labor compensation (increases in the labor cost index and increases in average hourly earnings). Unemployment remains low and is projected to be as little as 5 percent by the beginning of 2016.[31]

Real GDP is projected to grow at 2.4 percent in 2015 and 2.7 percent for 2016.[32] According to Blue Chip Economic Indicators ("Blue Chip"), a monthly consensus survey of analysts' forecasts of the U.S. economic outlook, the majority of panelists believe the U.S. Fed will begin raising interest rates before the end of the year. The current projection is for the Feds fund rate target to be in the vicinity of 1.5 percent by the end of 2016, 25 bps lower than was projected in June 2015 Blue Chip Report.[33]

According to Consensus Economics' Long Term Financial Forecast, shown in Table 2, U.S. and Canadian 10-year government bond yields should rise gradually to reflect movement towards tighter monetary policy.

Table 2: Long Term Forecast for 10-Year Government Bond Yields[34]

	2015	2016	2017	2018	2019	2020	2021-2025
Canada	1.6	2.1	3.2	3.6	3.7	3.9	4.0
U.S.	2.2	2.8	3.9	4.1	4.2	4.3	4.3

30 Bloomberg.com/quote/CL1:COM, accessed September 14, 2015.
31 Blue Chip Economic Indicators, September 10, 2015 at p. 1.
32 Ibid.
33 Blue Chip Economic Indicators (September 10, 2015) at 1; and Blue Chip Economic Indicators (June 10, 2015) at p. 1.
34 Consensus Forecasts by Consensus Economics Inc., Survey Date April 13, 2015.

B. Changes in Capital Markets since 2012

At the time of the August 2012, Stage 1 GCOC Application, the economy had begun its recovery from the global financial crisis. The evidence submitted by FEI in its Application, of generally a June 2012 vintage, revealed that the Bank of Canada found the risks to the Canadian financial system to be "high" due to a number of factors emanating primarily from the external environment, such as: escalation of the euro-area sovereign debt crisis, an economic slowdown in other advanced economies, financial stress in the Canadian household sector, a disorderly resolution of global current account imbalances, and excessive risk-taking associated with a prolonged period of low interest rates.[35] Conditions reported in the June 2015 Financial System Review, discussed in detail above, reflect a slow improvement as the Bank noted key risks to the financial system ranged from "moderate" to "elevated," indicating systemic risks of the Canadian financial system are lower in June 2015 than they were when FEI last filed cost of capital evidence in its Stage 1, GCOC Application. This tone was somewhat moderated in the Bank's September release, when it indicated:

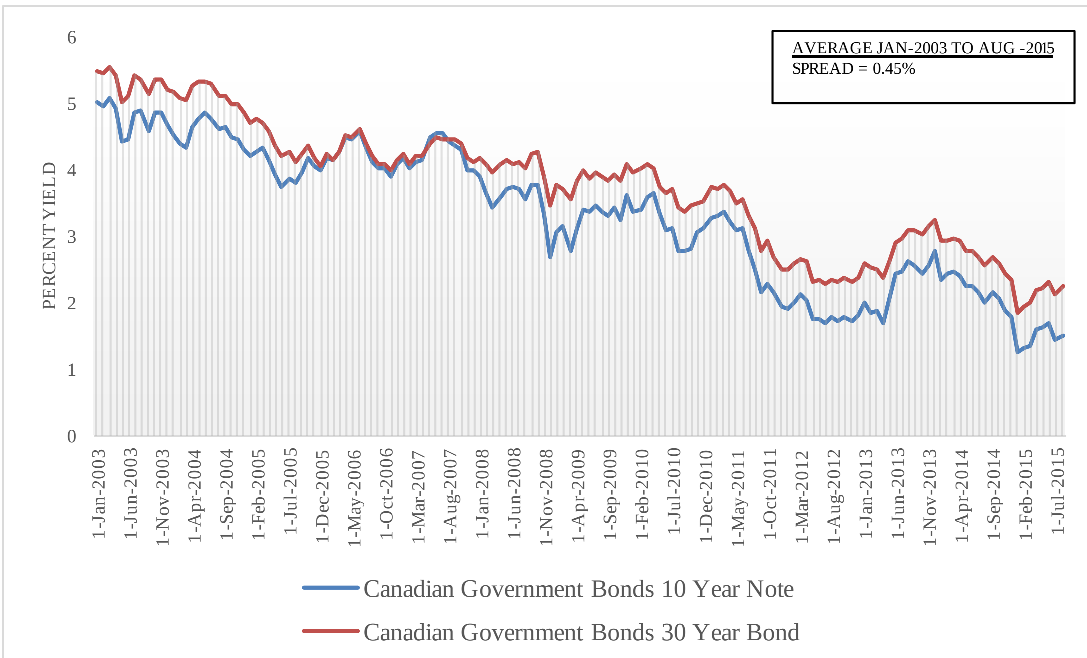
> Increasing uncertainty about growth prospects for China and other emerging-market economies, in contrast, is raising questions about the pace of the global recovery. This has contributed to heightened financial market volatility and lower commodity prices. Movements in the Canadian dollar are helping to absorb some of the impact of lower commodity prices and are facilitating the adjustments taking place in Canada's economy. While the overall export picture is still uncertain, the latest data confirm that exchange rate-sensitive exports are regaining momentum.[36]

As reflected in Figure 1, The 10 and 30-year long term Canadian government bond yields of 1.739 percent and 2.329 percent, respectively, in June 2012, have moved slightly lower and are currently at 1.493 and 2.235 percent, respectively as of August 31, 2015.[37] The spreads between the 10-yr and 30-yr Canadian government bonds have also increased from 59 bps in 2012 to 74 bps in August 2015 indicating an expectation that bond yields

35 Bank of Canada, Financial System Review (June 2012) at p. 1.
36 Press Release. "Bank of Canada maintains overnight rate target at 1/2 per cent." Bank of Canada, September 9, 2015.
37 Bloomberg data as of August 31, 2015.

will remain low in the near term, but will move higher during later economic growth periods. As Figure 1 reveals, these bond yields are very near to all-time lows and reflect the prolonged quantitative easing that has occurred in both Canada and the U.S. following the global economic crisis and investors' flight to quality.

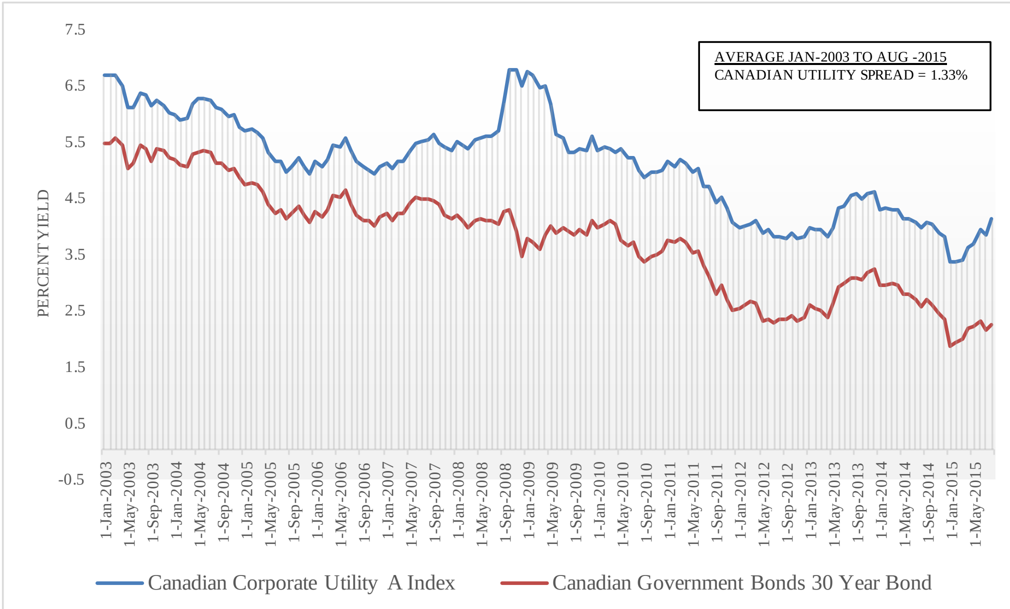
Figure 1: Canadian Government Bond Yields - 10-Year and 30-Year



Source: Bloomberg series GCAN10YR and GCAN30YR as of August 31, 2015

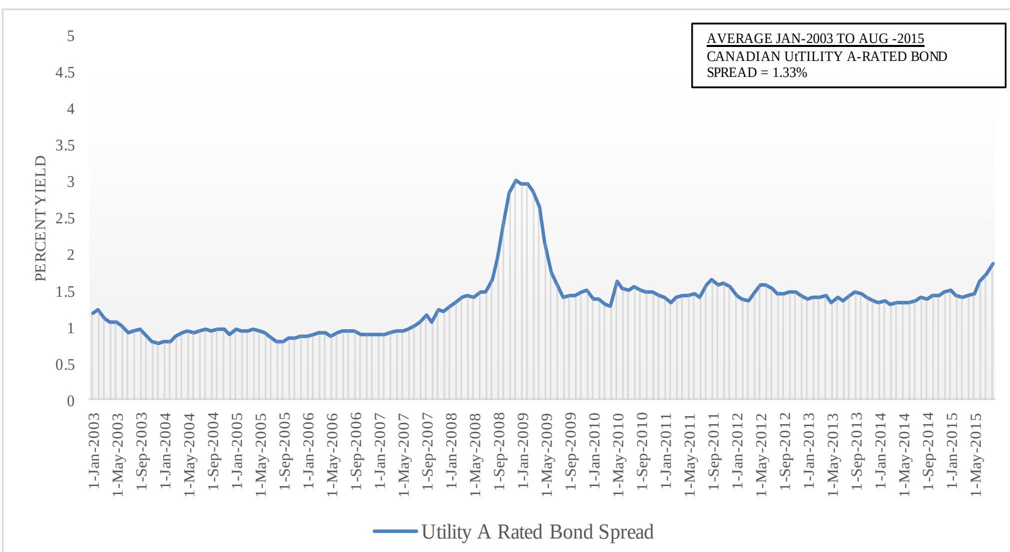
Yields on corporate bonds and spreads are slightly higher from where they were in June 2012. As Figures 2 and 3 show, the Canadian Utility A-rated bond yield index was 3.92 percent in June 2012, compared to 4.10 percent in August 2015, an increase of 18 basis points. The Canadian Utility A-rated spread over 30-year government bonds was 1.588 percent in June 2012 versus 1.868 percent in August 2015, an increase of 28 basis points, indicating ongoing risk aversion in the wake of continued economic uncertainty.

Figure 2: Canadian Utility A-Rated Bond vs. 30-Year Canada Long Bond



Source: Bloomberg series C29530Y and GCAN30YR as of August 31, 2015

Figure 3: Canadian Utility A-Rated Bond Spread vs 30-Year Canada Long Bond

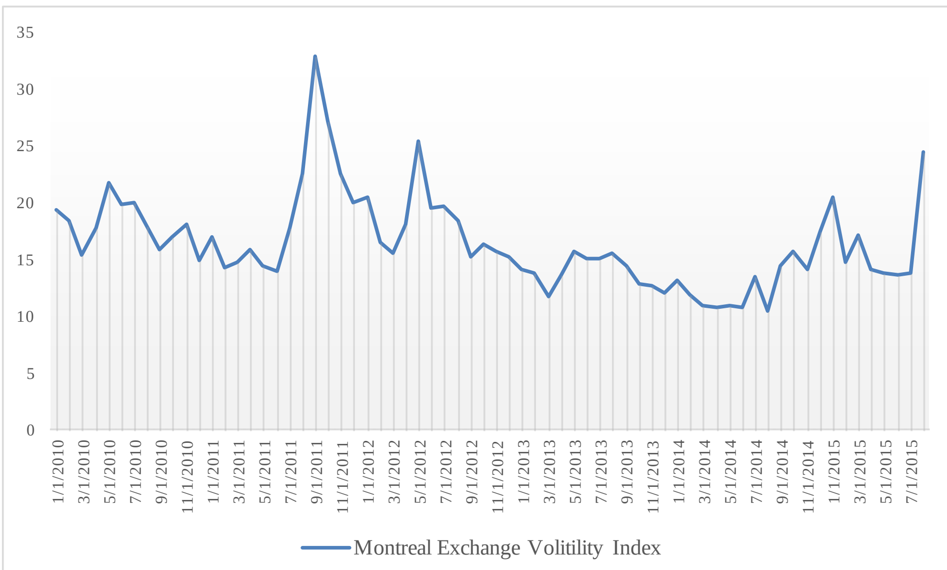


Source: Bloomberg series C29530Y and GCAN30YR as of August 31, 2015

Generally, current capital market conditions are not dissimilar to what they were in June 2012. Capital markets continue to recover from the global economic crisis of 2008-2009, but at a slower than expected pace and have shown little change from when FEI last filed its GCOC evidence in 2012. Bond yields have remained low and utility bond spreads have remained somewhat elevated, with no significant movements since June 2012.

The Montreal Exchange[38] Volatility Index pictured in Figure 4, reflects greater volatility in August 2015 compared to June 2012, with volatility increasing from the June 2012 level of 19.52 to the current level of 24.47 in August 2015.

Figure 4: Montreal Exchange Volatility Index



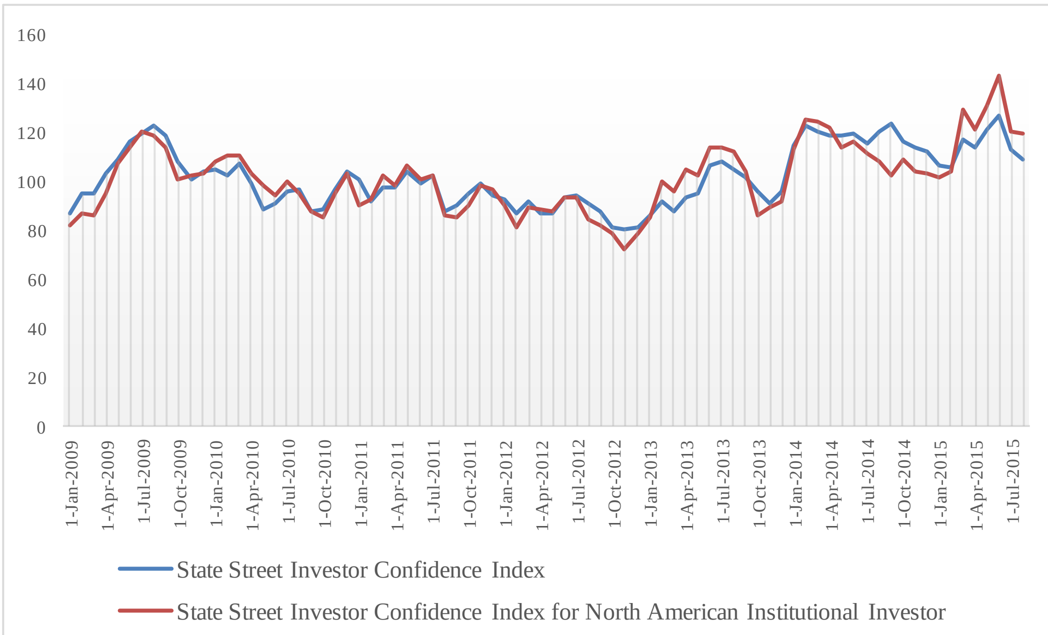
Source: Bloomberg VIXC Index as of August 31, 2015

The investor confidence index, published by State Street Bank in the U.S., provides a quantitative measure of global risk tolerance of the world's sophisticated investors. The index assesses investor confidence by reviewing the risk of investor portfolio investments. As portfolio risk increases, it is attributed to an increase in investor confidence. A review of the investor confidence index over time, in Figure 5, reveals a bumpy and downward slide during the global economic crisis of 2009. Investor confidence was relatively stable in June of 2012, and began a bumpy climb upwards to current levels in August 2015.

38 The Montréal Exchange (MX), Canada's oldest exchange, is a fully electronic exchange dedicated to the development of the Canadian derivative markets.

Similar to the Montreal Exchange Volatility Index, the State Investor confidence has taken a recent downward turn from high levels two months prior. The North American Institutional Investor Confidence Index (which focuses exclusively on institutional investors domiciled in the U.S. and Canada) shows a similar progression.

Figure 5: State Street Investor Confidence Indices



Source: Bloomberg SSICCONF Index and SSICAMER Index as of August 31, 2015

To provide a view of how these capital market conditions have been reflected in the Canadian stock market, below is a snapshot of a sampling of key market indicators for both S&P/TSX Composite index and also the S&P/TSX 60 Index. The S&P/TSX Composite is a broad market index, comprised of the largest companies on the Toronto Stock Exchange (measured by market capitalization). The companies listed in this index comprise approximately 70 percent of the market capitalization for all Canadian companies listed on the TSX. The S&P/TSX 60 is a stock market index of 60 large companies on the Toronto Stock Exchange, which exposes investors to ten distinct industry sectors.

The S&P/TSX Composite and the S&P/TSX 60 price indices have increased since June 2012, earnings have increased modestly, dividends have increased, but dividend yields have remained constant. As a result, the ratio of dividend yields to government bonds (D/Y ratio), increased slightly from 1.9X to 2.1X; and for the S&P/TSX60 increased from 1.8X to 2.1X. Over this same period, the 10-year Government bond yield decreased from 1.7 percent to 1.49 percent. This reinforces that dividend yields, may, and often do, become dislocated from bond yields, and though generally move in the same direction do not track each other exactly. Accordingly, it is important to include a test based on bond yields such as the CAPM or risk premium approach, as well as a test based on dividend yields, such as the DCF test, to provide a robust ROE analysis.

Table 3: TSX Market Indicators

	June 2012 [1]	August 2015
S&P/ TSX Composite		
Price Index	11,597	13,859
Earnings	$789.00	$802.38
Dividends	$365.80	$433.98
Trailing P/E	14.70X	20.28X
Dividend Yield	3.20%	3.13%
Long Term Growth Rate	3.36%	13.82%
D/Y Ratio	1.9X	2.1X
S&P/ TSX 60		
Price Index	664	815
Earnings	$48.00	$50.38
Dividends	$20.90	$25.46
Trailing P/E	13.80X	18.81X
Dividend Yield	3.10%	3.12%
Long Term Growth Rate	3.01%	14.47%
Forward P/E [2]	12.60X	15.94X
Forward Earnings Yield (E/P) [3]	7.94%	6.27%
D/Y Ratio	1.8X	2.1X
10-year Canada Bond Yield	1.70%	1.49%

Notes:
[1] Per Direct Evidence of Kathy McShane in BC GCOC Proceeding (August 2012) at 32.
[2] Forward P/E ratio is 12/31/2015 Bloomberg Estimate.
[3] Forward Earnings Yield is calculated by dividing 1 by the Forward P/E
Source: Data from Bloomberg

In summary, equity valuations have increased reflecting greater investor confidence in equity markets as the economy continues its recovery. This confidence is readily swayed, however, by new market information and monetary policy. As indicated in the previous section, the expectation is that tighter monetary policy and economic growth in the upcoming year will lead to higher interest rates in both the U.S. and Canada. Though financial markets have reflected more optimism in valuations, recent financial market volatility indicates that optimism may be waning and uncertainty persists in today's financial markets, as it did in June 2012, as the pace of recovery proves slower than expected and the impact of China's economic slowdown has yet to be fully realized on the global economy. Though it is difficult to predict what will unfold, I would not characterize the global economy as appreciably improved today from where it stood in its recovery in June 2012, and accordingly, I would not expect investors to view current capital market conditions as dissimilar to those in June 2012.

C. <u>Integration of Canada and U.S. Capital Markets</u>

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 economies and the business environments.

Country-specific economic and business conditions that affect investment risk may be measured through a variety of qualitative and quantitative metrics. One such measure, produced by the Economist Intelligence Unit (affiliated with the *Economist* magazine), ranks the world's largest economies based on a range of factors impacting the business environment. According to the report:

> The business rankings model measures the quality or attractiveness of the business environment in the 82 countries covered by *The Economist Intelligence Unit's Country Forecast* reports. It is designed to reflect the main criteria used by companies to formulate their global business strategies, and is based not only on historical conditions but also on expectations about conditions prevailing over the next five years…

> … The business rankings model examines ten separate criteria or categories, covering the political environment, the macroeconomic environment, market opportunities, policy towards free enterprise and competition, policy towards foreign investment, foreign trade and exchange controls, taxes, financing, the labor market and infrastructure. Each category contains a number of indicators that are assessed by the Economist Intelligence Unit for the last five years and the next five years. The number of indicators in each category varies from five (foreign trade and exchange regimes) to 16 (infrastructure), and there are 91 indicators in total. Each of the 91 indicators is scored on a scale from 1 (very bad for business) to 5 (very good for business).[39]

The business environment ranks are updated annually in individual country forecasts. Based on the 2014 update, which provides the projected 2014-2018 rank for 82 countries, the business environments of Canada and the U.S. are ranked 4th and 7th, respectively over the projected five years.[40] This report suggests that from a business investment perspective, Canada and the U.S. are highly comparable in a global context.

A Discussion Paper presented by the Bank of Canada discusses the linkage between the U.S. and Canadian economies, noting that:

> For Canada in particular, developments in U.S. economic activity and financial conditions are likely to exert a significant effect on the Canadian business cycle. Historically, the effect of the U.S. business cycle on the Canadian business cycle has generally been studied through trade linkages, since the United States represents about three-quarters of Canadian trade. However, there are also strong financial linkages between Canada and the United States. For example, Canadian non-financial corporations rely on U.S. financing, since about 20 per cent of shares of Canadian firms are held by U.S. residents. Moreover, foreign loans typically account for about 40 per cent of total bank loans to the Canadian non-bank sector, highlighting the importance of foreign credit for Canada [excluding mortgages]. Therefore, developments in U.S. financial conditions may exert a significant effect on the Canadian business cycle.[41]

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[39] The Economist Intelligence Unit "Business Environment Rankings; Which country is best to do business in?," Economist Intelligence Unit Limited 2014, at p. 8.

[40] Ibid at pp. 1 and 6.

[41] Financial Spillovers Across Countries: The Case of Canada and the United States, Bank of Canada

Exhibit JMC-2 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. The first measure compares the returns to investors from the S&P/TSX and S&P 500 stock indices. From 1990 through 2014, the total return on the S&P/TSX was 9.31 percent compared to 11.25 percent for the S&P 500. We note that returns for the period have been highly correlated[42] at 0.71, *i.e.* they move together for the most part. Turning to utility stock indices, U.S. utility returns have typically shown a close historical relationship to Canadian utility returns over the last 10 years, with U.S. utility returns exceeding the Canadian returns by 1.29%. These returns were positively correlated at a coefficient of 0.64 for the 12 year period for which data is available.

As also shown on Exhibit JMC-2, the correlation between real GDP growth rates in the two countries is strong, as is the correlation between the consumer price indices for each country, indicating that these metrics tend to move together over time between the two countries. Over the 25-year period, real GDP growth has been 2.29 percent in Canada and 2.41 percent in the U.S., while consumer inflation has been 2.08 percent in Canada and 2.63 percent in the U.S. Unemployment rates over the 25 year period have averaged higher in Canada (*e.g.,* 7.40 percent in Canada vs. 6.12 percent in the U.S. since 1990), but that trend reversed in 2008 where U.S. unemployment exceeded that in Canada. The average for the 5-year period was 6.74 percent for Canada and 8.02 percent for the U.S.; and for the 10-year period was 6.30 percent and 6.95 percent for Canada and the U.S., respectively. This shows that the U.S. was harder hit by the recent recession then its Canadian neighbors. As the U.S. continues its economic recovery, we note that the gap in 2014 unemployment rates between the two countries has closed, and 2014 U.S. unemployment of 6.2 percent was lower than that in Canada by 0.50 percent.

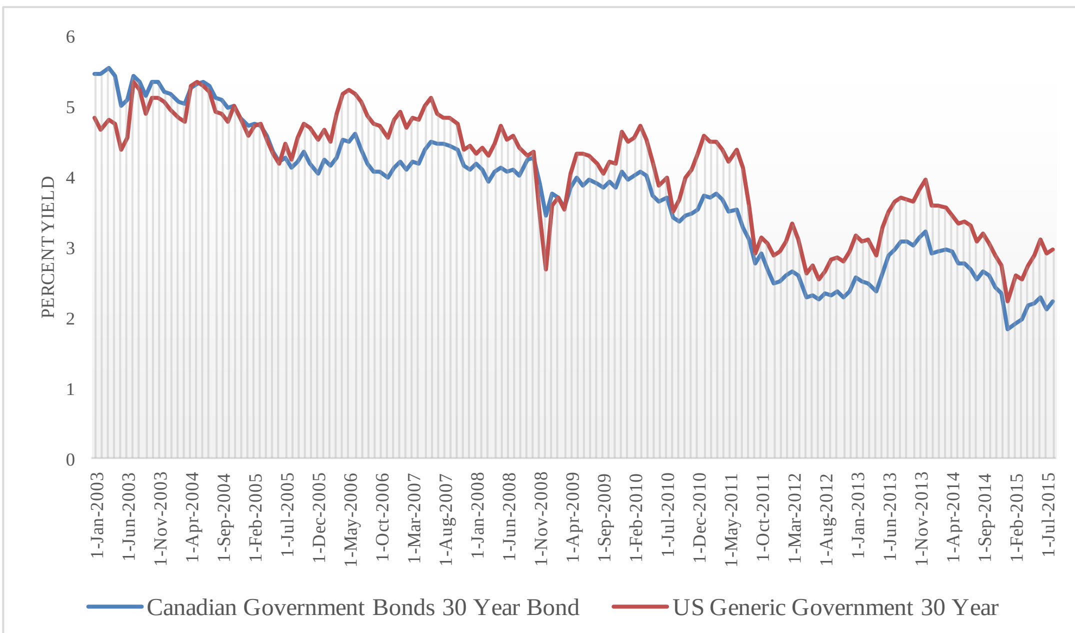
The average yields on 10-year government bonds have also been similar in Canada and the U.S. Over the past decade, the average yield on 10-year Canadian government bonds was 3.17 percent, while the average yield on U.S. 10-year Treasury bonds was 3.33 percent.

Discussion Paper, 2011-1, Kimberly Beaton and Brigitte Desroches, January 2011, at p. 1.

42 Correlation measures the strength of the linear relationship. Two variables moving along identical paths in the same direction will have a correlation of 1.0; if the two variables move in perfectly opposite directions, they will have a correlation coefficient of -1.0; and if they exhibit no signs of a linear relationship, the two variables will have a correlation coefficient of 0.

The 5-year averages for the Canadian and U.S. 10-year government bond yields are close at 2.46 percent for Canada and 2.54 percent for the U.S. The average yield on 10-year government bond for 2014 was 2.23 percent in Canada and 2.53 percent in the U.S. The correlation between average yields on 10-year government bonds in Canada and the U.S. since 1990 has been strong at 0.97, the highest of all macroeconomic indicators compared. Correlations of this degree are reflective of closely integrated financial markets. As shown in Figure 6, Thirty-year Government Bonds are also highly correlated at 0.93.

Figure 6: Canadian and U.S. 30-Year Government Bond Yields



Source: Bloomberg data as of August 31, 2015

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. In 2014, in terms of trade in goods, 76.8 percent of Canada's total exports went to the U.S., and imports from the U.S. accounted for 54.3 percent of Canada's total imports.[43]

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

[43] Source: Trade Data Online – Canadian Trade Industry, Industry Canada.

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. (*i.e.*, in terms of economic growth, inflation, unemployment, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparably situated utilities in the two countries. My cost of capital analysis is framed by the conclusions that Canada and the U.S. have comparable macroeconomic and investment environments. I consider both Canadian and U.S. proxy companies for my analysis.

IV. SELECTION OF PROXY COMPANIES

A. Why it is Necessary to Select a Proxy Group

Since the ROE is a market-based concept, and given the fact that stand-alone FEI is not a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to FEI in certain fundamental business and financial respects to serve as its "proxy" for purposes of the ROE estimation process. The BCUC has indicated in prior decisions that the return on equity should be set on a "stand-alone" basis, as if the Company were independently seeking to attract capital in the financial markets.[44]

Even if FEI's regulated gas distribution operations made up the entirety of a publicly traded entity, it is possible that transitory events could bias that entity's market value in one way or another over a given period of time. A significant benefit of using a proxy group, therefore, is its ability to mitigate the effects of anomalous events that may be associated with any one company. 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 FEI's regulated gas distribution operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

44 See, BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at p. 100.

Notwithstanding the care taken to ensure comparability, market expectations with respect to future risks and growth opportunities vary from company to company. 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 company-specific risks relative to the proxy group and the informed judgment and experience of the analyst.

Recognizing there are no publicly-traded, pure-play gas distribution companies in Canada, I have selected a sample of Canadian utilities to provide a benchmark for the risks and resulting cost of capital for Canadian utilities in general. In order to measure market expectations specific to a gas distribution utility, I developed a sample of U.S. companies that are primarily engaged in natural gas distribution.

B. <u>Precedent for Considering U.S. Data</u>

Canadian regulators have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for a Canadian regulated utility. The development of a proxy group comprised entirely of Canadian gas distribution utilities is limited by the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than regulated natural gas distribution service. This problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies.

The BCUC has accepted the use of U.S. proxy group data in Canadian ROE analysis, primarily due to the lack of sufficient Canadian data to produce a robust analysis. The Commission stated:

> …the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers

> that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.[45]

The BCUC reaffirmed its position on the use of U.S. data in its May 2013 GCOC Decision and also acknowledged the importance of providing a return that allows competition for capital in the global marketplace. The Commission stated:

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

The BCUC clarified, however, that though it accepts the use of U.S. data and the general comparability of U.S. utilities and regulatory models to their Canadian counterparts, it does not consider them the same or necessarily to deserve equal weight in the ROE analysis. The Panel concluded that "the use of U.S. data must be considered on a case-by-case basis and weighed with consideration of the sample being relied upon and any jurisdictional differences which may exist."[46]

In summary, the BCUC has recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data is limited by the small number of publicly-traded utilities. Concentric's analysis supports that it is reasonable and appropriate to consider the results of a risk-comparable U.S. proxy group for purposes of establishing the allowed ROE for a Canadian natural gas or electric utility.

[45] 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 pp. 15-16.

[46] BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at pp. 19-20.

C. Proxy Groups

I developed two primary proxy groups for my analysis. The first proxy group is comprised of publicly-traded regulated Canadian electric and natural gas utility companies. Because there are relatively few publicly-traded companies in the Canadian utility sector, the only screening criterion was an investment grade credit rating, which all companies in the sector have. I have excluded TransCanada, which is subject to a completely different set of competitive risks than the average natural gas distribution utility. I have included Fortis Inc. among the proxy group companies, which one could argue might introduce some circularity into the analysis, but given the relatively pure play nature of Fortis Inc. (93 percent of assets dedicated to utility service), I have decided to include Fortis Inc.[47] It also expands the relatively small Canadian proxy group from four to five companies. As will be seen, this does not have an appreciable impact on the results. I have included Enbridge, Inc. although its substantial oil and gas pipeline business present different business risks than the regulated gas distribution business. I have also included Emera, even though they have no natural gas distribution, and it recently announced its plans to acquire TECO in the U.S.

The following five companies comprise the Canadian Utility Proxy Group:

- Canadian Utilities Limited
- Emera Inc.
- Enbridge Inc.
- Fortis Inc.
- Valener Inc.

The second proxy group is comprised of like-risk U.S. natural gas distribution companies. To obtain companies of like-risk, I performed a number of screens to determine a group of essentially pure-play gas utilities with similar risk profiles to FEI. I started with the eleven companies Value Line classifies as Natural Gas Distribution Companies. From that group of 11 companies, I further screened for companies characterized by:

[47] The sale of Fortis Inc.'s hotel and property businesses, scheduled to be completed this fall, brings the corporation closer to a pure-play utility business (see Canadian Business, July 6, 2015).

- Credit ratings of at least BBB+ from S&P, or Baa1 from Moody's;
- Pay quarterly cash dividends;
- Earnings growth rates from at least two utility industry analysts;
- At least 70 percent of their operating income from regulated operations in the period from 2012-2014;
- At least 70 percent of their regulated operating income from natural gas distribution service in the period from 2012-2014; and
- Not involved in a merger or other significant transformative transaction during the evaluation period.

The following seven companies met those criteria:

- Atmos Energy Corporation
- New Jersey Resources, Inc.
- Northwest Natural Gas Co.
- Piedmont Natural Gas Co., Inc.
- South Jersey Industries, Inc.
- Southwest Gas Corporation
- WGL Holdings Inc.

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, but generally the primary factors impacting those risks are the same. The credit rating screen has been accepted by regulatory agencies, including the Federal Energy Regulatory Commission ("FERC"), which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[48] FEI is rated A3 by Moody's, the equivalent of an A- rating by S&P, while the average Moody's and S&P credit rating for the U.S. proxy group of gas distribution companies is A3 and A-, respectively.

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 vast 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 FEI's risk profile, I additionally screen for over 70% of operating income from the regulated natural gas distribution business. The final screen for companies involved in mergers avoids the problem of market data which has been distorted by the inevitable price movements prior to and following a merger announcement.

Though I have been able to screen U.S. companies that are relatively pure-play natural gas distribution companies, there are several companies in the Canadian proxy group engaged in non-regulated operations at the corporate level. As shown on Exhibit JMC-1, only three of the five companies in the Canadian proxy group derived more than 70 percent of their operating income from regulated activities; and only one company, Valener would also satisfy the regulated gas utility screen. This is a clear indication that a Canadian utility group cannot be created to reliably resemble the risks and business profile of FEI. If more Canadian companies met these screens, I could create a North American proxy group for gas utilities, as I have in other proceedings for electrics.

Non-regulated operations are not a significant concern for the U.S. proxy group because, as also shown on Exhibit JMC-1, regulated gas distribution service averaged approximately 95 percent of operating income and 85 percent of assets for those companies in the period from 2012-2014. Furthermore, I have conducted a business risk analysis of each proxy

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

group company at the operating company level enabling a detailed comparison of each company's regulated gas utility operations relative to FEI.

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

The required ROE is estimated by 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 and the DCF methods in developing an ROE recommendation for FEI within the context of the risk analysis discussed later in my testimony.

B. Importance of Using Multiple Approaches

When faced with the task of estimating the cost of equity, analysts are inclined to gather and evaluate as much relevant data (both quantitative and qualitative) as can be reasonably analyzed. 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 return on equity, but 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."[49]

Though 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 as a result of changes in economic conditions could have widely different impacts on the results of the various analyses. This view is widely held among financial practitioners, myself included, and is consistent with that offered by the Brattle Group in its survey report commissioned by the BCUC for the 2013 GCOC proceeding:

> It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured.[50]

The CAPM analysis (one form of equity risk premium approach) is a market test, based on the relationship between risk and required return. 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. This 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 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 resides 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.

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49 See Hope and Bluefield
50 The Brattle Group (May 31, 2012) – Survey of Cost of Capital Practices in Canada, at p. 3.

This premise is 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 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.[51] 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 CAPM would predict, and high beta stocks earn less than predicted. The Brattle Group pointed out this issue in its report for the BCUC:

> Perhaps the most fundamental challenge to the CAPM has been the consistent empirical observation that the model does not explain stock performance well in a statistical sense. For example, low beta stocks tend to have higher average returns than predicted by the CAPM, and high beta stocks have lower average returns – that is, the empirical estimates seem to require a pivot of the SML around beta = 1.0 from the traditional version of the CAPM.[52]

All of the above factors suggest that the CAPM has shortcomings. While appealing for its simplicity and broadly utilized in corporate finance, the CAPM has been challenged by a large body of empirical evidence and financial theory that question the plausibility of its assumptions, the assumed behavior of investors, and the ability to test the model against market data that fully represents the choices of investors. 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.

The DCF analysis is based on the principle that investors will bid the lowest acceptable stock 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

51 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).

52 Brattle, Ibid, at p. 25.

than would a lower risk investment. Investors will pay as much for a given share of stock as the next best alternative, *i.e.* next lowest risk-adjusted price. The investor's required return is the equalizing factor that allows investors to compare investments of varying degrees of risk. The DCF model theory infers the investors' required return by observing the price and dividend (earnings) stream of the stock, *i.e.* the model solves for the discount rate implied by the prevailing stock price by estimating future cash flows. 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.

The two primary forms of DCF model employed in practice are the constant growth and the multi-stage growth models. The constant growth model makes the simplifying assumption that growth is consistent over the life of the company. Fortunately, this restriction is less of a constraint when modeling utilities with predicable earnings and dividends. Generally, analyst growth rates are modeled in perpetuity. The multi-stage growth model assumes that current growth rates are not sustainable, and over the long term, the company's growth will revert in perpetuity to the growth rate of the broader economy (usually GDP growth).

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 and CAPM are relatively simple models to estimate the cost of capital, which by its nature is actually quite complex. No one model can reliably estimate the cost of capital that meets all three criteria of the Fair Return Standard. Only by applying multiple tests and employing our best judgment can we be assured of a reasonable estimate of the required return on equity.

C. Previous Methodologies and Inputs Accepted by the BCUC

The Commission Panel has previously recognized both the DCF and CAPM models as the "two most compelling frameworks for assessing the cost of equity;" and that those models have "well understood theoretical bases and explicitly recognize the opportunity cost of capital."[53] In the past GCOC Decision, the Commission gave equal weight to these two models.[54] In its previous 2009 Terasen Decision, the Commission gave "the most weight to the DCF approach, lesser weight to the ERP [Equity Risk Premium] and CAPM approaches and a very small amount of weight to the CE [Comparable Earnings] approach."[55] Thus, the Commission has varied between equal and the most weight to the DCF in this period.

With respect to the CAPM inputs, the Commission acknowledged that monetary policy had caused risk free interest rates to be unusually low and agreed in such circumstances it was reasonable to measure the opportunity cost to investors using a forecasted long-term risk free bond yield. With respect to the market risk premium, the Commission gave the greatest weight to measures of the historical risk premium, noting also that a DCF-based estimate of forward-looking market risk premium was a helpful check on the risk premium.[56] Lastly, with respect to betas, the Commission acknowledged that raw betas tend to understate the risk of relatively low-risk firms such as utilities and overstate the risk of high-risk firms, and that it is necessary to make an upward adjustment to the raw beta to correct for this failing in the CAPM. However, the Commission did not endorse any specific method of adjustment, though it did express concern that an adjustment towards the market risk average of 1 seemed inconsistent with the lower risk in the utility industry.[57]

With respect to the DCF model, the Commission expressed skepticism that analyst growth rates portray reasonable perpetual growth rates in the constant growth DCF model and for that reason placed more weight on the results of the multi-stage DCF and little weight

53 BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at p. 56.
54 Ibid.
55 BCUC Terasen Gas Inc. Return on Equity and Capital Structure, decision, December 16, 2009, at p.65.
56 BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at p. 62.
57 Ibid at pp. 63-64.

on the estimates for the constant growth DCF.[58] The Panel recognized the need to augment Canadian data with U.S. data, given the lack of pure play, publicly-traded Canadian utilities. However, the Panel emphasized the need for informed judgment in adjusting U.S. based estimates to reflect differences in respective environments. Though the Panel found reason to be cautious of potential analyst bias in the utility sector, the Panel was not convinced that an adjustment for analyst bias was necessary.

The Commission placed no weight on the Equity Risk Premium method, due to the lack of clarity produced by ad-hoc model variations. The Commission determined that there was ample evidence provided by the DCF and CAPM analyses and accordingly an equity risk premium analysis was not necessary. Similarly, the Commission placed no weight on the comparable earnings methodologies put forward, due to what the panel referred to as "serious problems" with that method.[59]

Lastly, the Commission accepted that an allowance for flotation and financial flexibility of 50 bps be added to both the DCF and CAPM results to account for equity issuance costs and to provide for some cushion or flexibility in capital financing arrangements.[60]

D. Methods Used to Determine FEI's Cost of Equity

1. Capital Asset Pricing Model

a. CAPM Analysis

The CAPM is based on a theoretically-derived relationship between a security's required return and the systematic risk of that security. As shown in Equation [1], the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

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

Where:

Ke = the required ROE for a given security;

[58] Ibid at p. 71.
[59] Ibid at p. 56.
[60] BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at p. 80.

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:

re = 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.

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, if possible.

i. <u>Risk Free Rate</u>

My CAPM analysis relies on the 2016 through 2018 average Consensus Economics forecast of the Canadian 10-year government bond (shown previously in Table 2, and repeated below in Table 4) and adds the historical spread between 10-year and 30-year government debt.[61] This period has been chosen to match the period when FEI's rates are most likely to be in effect.

[61] The Commission Panel has accepted the use of a forecast yield on the long-term risk free bond in its two previous GCOC proceedings. *See* BCUC Terasen Gas Inc. Return on Equity and Capital Structure, Decision, December 16, 2009, p.60 *and* BCUC Generic Cost of Capital Proceeding (Stage 1), Decision

Table 4: Long Term Forecast for 10-Year Government Bond Yields 2016-2018[62]

	2016	2017	2018	Average
Canada	2.1	3.2	3.6	**2.97**
U.S.	2.8	3.9	4.1	**3.60**

With an average historical spread between 10-year and 30-year Government bond yields of 71 basis points in Canada and 69 basis points for the U.S.,[63] the corresponding yield on 30-year government bond yields over the period 2016 – 2018, are 3.68 percent for Canada and 4.29 percent for the U.S.

Table 5: Risk Free Rate

30-Year Risk Free Yield	CDN$	U.S. $
April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield	2.97%	3.60%
Average Daily Spread between 10-year and 30-year government bonds (August 2015)	0.71%	0.69%
Average	**3.68%**	**4.29%**

Source: Consensus Economics Survey Date April 2015; and Bloomberg for daily bond yields.

Use of the 2016 through 2018 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 in their forward-looking return expectations. Otherwise, the results produced by the CAPM would not reflect forward-looking circumstances. The 30-year bond yield is appropriate to estimate the expected return on FEI's equity, as it best matches the lives of utility assets on which the return depends, with the term of the risk free instrument.

(May 10, 2013) at 59, noting that "all of the experts submit that the appropriate opportunity cost is better measured by the forecasted yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted."

62 Consensus Forecasts by Consensus Economics Inc., Survey Date April 13, 2015.

63 Historical spreads were calculated using daily bond yields published in Bloomberg from August 1, 2015 through August 31, 2015. The resulting averages were 0.712 for Canada and 0.691 for the U.S.

ii. Beta

Beta is a measure of risk and in this case it measures the volatility of a proxy group company's stock price relative to the aggregate market. It is typically calculated using a linear regression of the change in stock price returns vs. the change in general market index returns, where beta is the slope of the regression line. High betas (greater than 1.0) indicate greater covariance with the market and thus greater overall non-diversifiable risk, and therefore relatively greater risk. Conversely, low betas (lower than 1.0) indicate a lower covariance with the market, and lower risk.

I have examined several methods of measuring the beta coefficient for both the Canadian proxy group and the U.S. gas distribution proxy group companies using estimates from both Value Line and Bloomberg.[64] 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.[65] The results have been rounded to the nearest five hundredths, and no information is reported regarding the statistical significance of the underlying regression. Bloomberg, on the other hand, may produce beta estimates based on parameters entered by the user. 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. Bloomberg results are rounded to the nearest thousandth and include additional information regarding the statistical significance of the underlying regression. Both Value Line and Bloomberg betas are adjusted to compensate for the tendency of beta to revert towards the market mean of 1 over time.

There are two primary reasons to adjust raw betas. First, there have been empirical studies providing evidence that an individual company beta is more likely than not to move towards the market average of 1.0 over time. Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas that are greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas that are below the market average of 1.0 tend to have

[64] I have used Bloomberg betas for the Canadian proxy group and both Value Line and Bloomberg betas for the U.S. proxy group.
[65] http://www.valueline.com/sup_glossb.html.

negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 in an effort to improve forecasts.[66] Because current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.

There have been several studies to support the reversion of beta towards the market mean.[67] In 1971, Blume examined all common stocks listed on the NYSE, and found a tendency for a regression of betas towards 1.00. He concluded that:

> …there is obviously some tendency for the estimated values of the risk parameter to change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of βi tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios.[68]

In 1975, Blume revisited the topic, measuring the statistical significance of the regression tendency. He concluded:

> A comparison of the portfolio betas in the grouping period, even after adjusting for the order bias, to the corresponding betas in the immediately subsequent period discloses a definite regression tendency. This regression tendency is statistically significant at the five percent level for each of the last three grouping periods, 1940-47, 1947-54, 1954-61. Thus, this evidence strongly suggests that <u>there is a substantial tendency for the underlying values of beta to regress towards the mean over time</u>.[69]

[66] Roger A. Morin, *New Regulatory Finance*, at p. 74.
[67] Ibid.
[68] Marshall E. Blume, *The Journal of Finance*, Vol. 26, No. 1. (Mar., 1971), at p. 7-8 [emphasis added].
[69] Marshall E. Blume, *The Journal of Finance*, Vol. 30, No. 3. (Jun., 1975), at p. 794 [emphasis added].

I recognize that the BCUC expressed some reservation regarding the reversion of beta to the market mean in its 2013 GCOC Decision and adopted what it characterized as an "intermediate beta".[70] I therefore provide an alternative specification of beta that reverts to the midpoint of the market mean and an industry utility industry index.[71] Based on the strength of the academic literature, practice before regulatory commissions on such matters, and broader practice among financial analysts, I have relied on market-adjusted betas for my primary analysis. I present the alternative CAPM as a point of reference in the event the Commission determines that an alternative specification warrants any weight. The betas used in my analyses are presented below:

Table 6: Beta

	Canadian Group	U.S. Group
Adjusted to Market Mean (Primary Analysis)	0.65	0.78
Adjusted to Average of Industry Average and Market Mean (Alternative Analysis)	0.57	0.67

70 GCOC Decision, *Ibid*, at 64.

71 The Industry Index Beta is from the Bloomberg Professional average of five years of weekly betas for S&P Utilities index for the U.S. companies and the S&P/TSX Utilities index for the Canadian companies.

I would note that the betas I have used in my primary analysis are consistent with the findings of the Brattle study for this Commission:

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas may then be adjusted towards one as an adjustment for sampling reversion that was first identified by Professor Marshal Blume (1971, 1975).[72]

iii. Market Risk Premium

As the CAPM formula indicates, the market risk premium is a function of interest rates, *i.e.* 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 as interest rates rise, and rises when interest rates fall. It is well documented among financial theorists that the market risk premium is inversely related to interest rates.

Estimates of the market equity risk premium generally fall into two camps, ex-ante (or forward looking) and ex-post (historical average). An ex-ante approach may infer the market risk premium from DCF-derived or ERP-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-ante market risk premium can tell you what the market risk premium is today, based on currently anticipated economic and market conditions.

The ex-post market risk premium, provides a longer view of the investment horizon and may provide a better estimate of how the market will perform over a very long investment horizon, but is not sensitive to changes in interest rates and the prevailing economic environment. The ex-post market risk premium is calculated based on the arithmetic average of historical risk premia over the longest period for which data is available. Duff & Phelps calculates the risk premium for the U.S. as far back as 1926 and it calculates the Canadian risk premium as far back as 1919, from Morningstar Direct data.

[72] Brattle, Ibid, at p. 15.

It is appropriate to use the arithmetic mean of the historic market risk premiums as a starting point because the arithmetic mean, as opposed to the geometric mean, is the simple average of single period rates of return. The geometric mean is the compound rate that equates a beginning value to its ending value. The important distinction between the two methods is that the arithmetic mean treats each periodic return as an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean.…[the] geometric mean underestimates the expected annual rate of return.[73]

The arithmetic mean of the equity market returns over long-term government bond income returns as reported by Duff & Phelps is therefore used.

We begin the calculation of the market risk premium with the long-horizon equity risk premia data averaged over the longest period for which data were available from Duff & Phelps for both the U.S. and Canada. In the U.S., Duff & Phelps reports premia data from 1926-2014 and results in a market risk premium of 7.0 percent,[74] the arithmetic mean of the premium of the S&P 500 total returns for large company common stocks over long-term government bond income returns. In Canada, the longest period for which risk premia data is available from Duff & Phelps is from 1919 – 2014 in Canadian currency, which yielded an equity risk premium of 5.6 percent in Canadian dollars.[75]

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[73] Ian Cooper, "Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting," *European Financial Management 2.2* (1996): at p. 158.

[74] Duff and Phelps, 2015 International Valuation Handbook: Guide to Cost of Capital, Market Results through December 2014 and March 2015; United States Long-Horizon Equity Risk Premia in U.S. Dollars, Data Exhibit 1-40.

[75] Ibid, Canada Long-Horizon Equity Risk Premia in Canadian Dollars, Data Exhibit 1-9; and International Equity Risk Premia 3-9. The Canadian market, from 1970 to present, is represented by Duff & Phelps as the MSCI Canada GR Index (total return) series, which is designed to measure the performance of the large and mid-cap segments of the Canadian market. The index is comprised of 95 constituents making up

The shortcoming of using such a long horizon equity risk premia is it tends to be low in a low interest rate environment and high 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, as additional data has less weight in the average as time goes on. Since both the U.S. and Canadian economies have enjoyed a prolonged low interest rate environment, which seems to have accelerated downwards in recent months, it should be expected that the historical arithmetic average will understate the current market risk premium.

Because of this, I have incorporated a forward-looking risk premium (ex-ante) estimate to mitigate the inability of the long term historical average to respond to changes in capital market conditions. My ex-ante risk premium is based on capital market conditions on August 31, 2015, using forward projections of the return on the relevant market indices less the risk-free rate. I have used a forecast of the 30-year bond yield in my calculation of the ex-ante risk premium, which arguably lowers and moderates the risk premium result by the difference between the 30-year bond yield at August 31, 2015 (2.23%) and the forecast bond yield I have used to calculate the forward-looking market risk premium of (3.68%).

The BCUC commented on the use of a forward-looking market risk premium in its GCOC decision:

> Although the (CAPM) model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.[76]

Brattle also commented on this method:

approximately 85% of the free float-adjusted market capitalization of Canada. Prior to 1970, Duff & Phelps relied upon the Dimson, Marsh, Staunton equity returns for Canada.

76 BCUC, GCOC Decision, May 10, 2013, at p. 62.

> Some practitioners forecast the expected MRP. To do so, a DCF model is commonly used to estimate the expected return on the market (*e.g.,* the S&P/TSX companies) and subtracting the forecast government bond (or bill) yield to obtain a forward looking estimate of the expected premium that stocks command over bonds. This forecasted MRP can then be used with a forecasted risk-free rate to estimate the forward-looking CAPM estimate of the cost of equity. This method is also a version of the conditional MRP as the forecast depends on the economic circumstances at the time of the forecast.[77]

As shown in Exhibit JMC-4, Schedules 1 and 2, the forward return projections used in the computation of the forward-looking market risk premiums 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 Canada, I have used the S&P/TSX Composite index). I have used the DCF methodology to determine the implied expected market return. Using this method, I have subtracted the forecast risk free rate from the expected market returns to arrive at the forward-looking equity risk premia results of 9.78 percent and 8.08 percent, respectively, for Canada and the U.S. In other words, investors in today's stock markets are indicating these projected returns over the risk free rate in their valuations of the companies in these broad market indices. These forward looking risk premiums suggest that a pure historical estimate is too low in today's low interest rate environment.

Because the U.S. and Canadian economies are integrated and capital flows freely across the border, arguably the independent risk premiums for each nation are highly correlated. In a 2002 study performed by Dimson, Marsh and Staunton, the authors indicate that when deriving a forward looking projection of required return on equity from a purely historical estimate of the risk premium, it is necessary to "reverse-engineer" the facts that impacted stock returns over the past 102 years, backing out factors that could not be anticipated to be recurring in the future, such as unanticipated growth or diminished business risk through technological advances. To this point, the authors' state:

> While there are obviously differences in risk between markets, this is unlikely to account for cross-sectional differences in historical premia.

77 Brattle, Ibid, at pp. 20-21.

> Indeed much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country by country approach to determining the prospective equity risk premium.

Accordingly, it is appropriate in markets that are more similar than not, and where good reason does not exist to expect a divergence in market risk premiums, to derive a single forward looking estimate. Concentric has used both an ex-ante and an ex-post derivation of the Market Risk Premium and has averaged both the Canadian and U.S. equity risk premiums to derive a combined North American equity risk premium.

As shown in Table 7, the market risk premium I have utilized in my CAPM is 7.6 percent. Combining U.S. and Canadian equity risk premiums into a single North American market risk premium is appropriate since the equity markets in the U.S. and Canada are more similar than not, and there is no reason to expect a divergence in market risk premiums going forward.

Table 7: Market Risk Premium Values

	Canadian MRP	U.S. MRP
Historical MRP	5.6%	7.0%
Forward-looking MRP	9.8%	8.1%
Average	**7.6%**	

I have tested my market risk premium estimates by conducting a regression analysis on long Canada bond yields and annual market risk premiums calculated by Morningstar Ibbotson through 2011; and by Duff & Phelps thereafter. As can be seen in Exhibit JMC-6, I have isolated the effects of the global financial crisis in 2008 as an anomalous event that did not align with the normal relationship between treasury yields and market risk premiums. I have set this period aside by assigning a dummy variable to it. My analysis yielded a statistically significant value at the 85 percent confidence level, and in my opinion is informative of the relationship between bond yields and market risk premiums. Note that the coefficient for 30-year bond yields is negative 1.11, such that a negative change in the bond yield results in an almost equal increase in the market risk premium - evidence that the market risk premium and bond yields are indeed inversely related. Using my 30-year Canadian bond yield forecast of 3.68 percent, the regression formula produced by my analysis yielded a market risk premium of 10.09 percent when the long Canada bond yield is 3.68 percent.

$$(MRP = 14.18\% + (-1.11 \times 3.68\%) + (-45.18 \times 0) = 10.09\%)$$

Accordingly, my estimate of the market risk premium of 7.6 percent is reasonable and appropriate and is more reflective of the current low interest rate environment than the long term average. Applying this MRP to the full expression of the CAPM formula, using the Canadian proxy group average beta of 0.65, would yield an ROE of 10.19 percent, when the Canada long bond is 3.68 percent; and 9.78 percent, when the Canada long bond yield is equal to the August 31, 2015 value of 2.23 percent.[78]

b. CAPM Results

I have used the average of the market-adjusted betas for the Canadian and U.S. proxy groups of 0.65 and 0.78, respectively, and the 3.68 percent projected yield on the Canadian long-term government bond. The results of the CAPM analysis, including flotation costs, are provided in Table 8 and are shown in detail in Exhibit JMC-5, Schedule 1.

Table 8: CAPM Results (includes 50 bps flotation cost)

CAPM Results

Inputs	Beta Adjusted to Market
	Canadian Utility Proxy Group
Forecast 30-yr GOC bond yield 3.68%; North American Market Risk Premium of 7.6%	9.08%
	U.S. Gas Distribution Proxy Group
	10.08%

As discussed previously, I have also estimated an alternative CAPM by averaging market-adjusted betas with utility industry-adjusted betas. The results of that CAPM analysis

[78] The derivations are based on the CAPM equation Ke = rf + β(rm – rf), where the term (rm – rf) is the market risk premium measured by the regression equation. The calculations are as follows: [3.68% + (0.65 x 10.09%)] = 10.19%; and [2.23% + (0.65 x 11.70%)]=9.78%, differences are due to rounding.

produced an ROE for the Canadian proxy group of 8.50 percent, and for the U.S. proxy group of 9.28 percent (inclusive of 50 bps for flotation) and can be found in Exhibit JMC-5, Schedule 2. Though I do not agree that utility betas should be adjusted towards anything other than the market mean, I provide these results as a point of comparison.

a. DCF Analysis

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. Efficient markets price a stock according to these expectations, leading to the expression 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 accordingly, as shown in Formula [4]:

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

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. 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.

b. Growth Rate Estimates

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 growth. While there are many methods that reasonably can be employed in formulating a growth rate estimate, an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking prospects for the company.

Investors typically rely on projected earnings growth as an indicator of dividend growth rates for several primary reasons. First, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order 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 rate 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.[79]

[79] 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.

Five-year earnings growth rates are publicly available from Zacks' Investor Services for U.S. companies. Yahoo! Finance, which is a public source, and SNL Financial, 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 group, but only one company in the Canadian proxy group.

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

The relationship between various growth rates and stock valuation metrics has been the subject of academic research.[80] 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.[81] 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 consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[82]

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

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

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

[82] 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.

> FAF have been used in conjunction with DCF models to estimate equity return requirements.[83]

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.[84] Although the purpose of that study was to "investigate what growth expectation is embodied in the firm's current stock price,"[85] 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.[86]

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".[87] 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.[88]

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.[89] Similarly, Brigham, Shome and Vinson noted that "evidence in the

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83 Ibid., at p. 60.
84 James H. Vander Weide, Willard T. Carleton, Investor growth expectations: Analysts vs. history, The Journal of Portfolio Management, Spring, 1988.
85 Ibid., at p. 78.
86 Ibid., at p. 82.
87 Robert S. Harris, Felicia C. Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management, Summer 1992.
88 Ibid., at p. 63.
89 Advanced Research Center, Investor Growth Expectations, Summer, 2004.

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."[90]

Optimism bias has been cited as a concern when using analyst growth rates. The concern is whether or not 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 are designed to provide fair disclosure and eliminate the possibility of analysts' bias. 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 the 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. A 2010 article in Financial Analyst Journal found that analyst forecast bias had declined significantly or disappeared entirely since the Global Settlement:

> 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

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

> 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.[91]

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 market place, by establishing requirements that reduce the potential for conflicts of interest and allow for the highest standards of ethical behavior."[92] The initial draft of Policy 11 was issued on April 12, 2001 and became effective on February 1, 2004. The Policy requires more disclosures from analysts and independence of research departments from investment banking departments[93] with the issuance of 20 requirements and 9 guidelines that must be complied with where practicable.

With respect to the DCF approach, the BCUC allowed equal weighting of the DCF and equity risk premium approaches to ROE analysis in its 2013 GCOC Decision. It also found that U.S. data can act as a proxy for Canadian data and has rejected suggestions of analyst bias, noting that no allegations of upward bias have been leveled against utility analysts. [94]

c. DCF Analysis and Results

i. Dividend Yield

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

[5] $$Y = \underline{D_0(1+0.5g)}$$

[91] 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.

[92] Investment Dealers Association of Canada, 13.1.2, IDA Policy No. 11.

[93] Bin Chang, *Playing Favourites, Bias in equity recommendations on Canadian stocks*, Canadian Investment Review (Fall 2009).

[94] BCUC Generic Cost of Capital Proceeding (Stage 1), Decision (May 10, 2013) at 71. Also see BCUC Terasen Return on Equity and Capital Structure Decision (December 16, 2009) at p. 45.

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 companies' current annualized dividend, and average closing prices for the 90-trading days ended August 31, 2015. 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.

ii. <u>Constant Growth Rate Model</u>

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' 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 forecasts are the best available estimates for future growth rates. Available earnings growth estimates from SNL Financial, Value Line, Zacks, and First Call for each company in the Canadian and U.S. proxy group were used. Those growth rates are shown on Exhibit JMC-7, Schedule 1.

iii. <u>Multi-stage DCF Model</u>

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 First Call 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 stage, or the 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 two hundred 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. The Commission seemed to endorse this approach in its 2013 GCOC Decision:

> The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.[95]

I have applied the Multi-stage DCF model to both the Canadian and U.S. proxy groups. The assumptions used with respect to the various model inputs are described in Table 9.

[95] Ibid., at p. 70.

Table 9: 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 and 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 both proxy groups were developed using available data for each country from Consensus Economics, Inc. for the period from 2021-2025, consistent with the Stage 3 period following year 11. These forecasts are based on 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. The estimates of nominal GDP growth that were utilized are summarized in Table 10 below:

Table 10: Estimates of Nominal GDP Growth [96]

Source	Canada	U.S.
Real GDP Growth	1.90%	2.30%
Inflation	2.00%	2.20%
Nominal GDP Growth	3.94%	4.55%

[96] Consensus Forecasts, for 2021-2025, April 13, 2015, Calculated as: Real GDP x (1+CPI)+CPI.

iv. DCF Results

The DCF results are shown Table 11 below and on Exhibit JMC-7, Schedules 1 and 2. As shown on the Table below, the DCF analyses across all methods indicate an average cost of common equity of 11.26 percent for the Canadian proxy group and 9.29 percent for the U.S. gas distribution proxy group, including a 50 basis point adjustment for flotation costs and financial flexibility.

Table 11: DCF Results (including 50 bps flotation costs)

	Constant Growth	Multi-Stage	Average
	Canadian Utility Proxy Group		
90-day averaging period	12.70%	9.82%	**11.26%**
	U.S. Gas Distribution Proxy Group		
90-day averaging period	9.68%	8.89%	**9.29%**

The adjustment for flotation costs and financial flexibility 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 BCUC has similarly allowed such an adjustment to reflect the risks associated with equity issuance and financing flexibility.[97] Consistent with this precedent, I have adjusted the CAPM and DCF results upwards by 50 basis points.

[97] BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at p. 80.

VI. BUSINESS RISK

In this section, I examine FEIs risk profile in the context of its request for a 40 percent equity thickness and how FEI's risk profile compares to its peers. 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 storms, supply constraints or financial market disruptions. 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: the risk of stranded assets due to loss of market share, or environmental policies that substantially 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.

In its May 2013 Generic Cost of Capital Decision, the BCUC reiterated eight primary factors that Terasen Gas Inc. (now FEI) had identified in its 2009 Cost of Capital proceeding that had exerted significant influence on FEI's long term risk profile. The same factors were identified as having still been relevant in the last GCOC proceeding. Those factors were:[98]

1) Provincial Government climate and energy policies;
2) The effect of aboriginal rights issues;
3) The competitive position of natural gas relative to electricity;
4) Percentage of new construction being captured by [FEI];[99]
5) Natural gas vs. Electricity in high density housing;
6) The impact of Alternative Energy Sources on [FEI];[100]

98 BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at p. 25.
99 Note that "FEI" has replaced the actual language in the Decision, which refers to FEI's predecessor "Terasen Gas Inc. (TGI)."
100 Ibid "(TGI)' replaced with "FEI".

7) Changes in demand related to fuel switching; and
8) Use of natural gas per customer account.

I have reviewed the influence of these factors on FEI's long term risk profile and note that the above list of factors remains relevant today and continues to impact the company's risk profile.

A. FEI's Business Risk Profile

Concentric has reviewed the business risk profile presented by FEI in its evidence in this proceeding, and conducted an independent analysis of FEI's risk profile. Though my list of typical risk factors is different than those listed in the BCUC's Decision, they broadly encompass the same risks and considerations as those identified in the previous cost of capital proceedings for FEI. The business risk factors I have examined are listed below in the order addressed:

1) Operating Risks
2) Gas Supply and Infrastructure Risk
3) Gas Price Levels and Volatility
4) Volume/Demand Risk
5) Political and Regulatory Risk

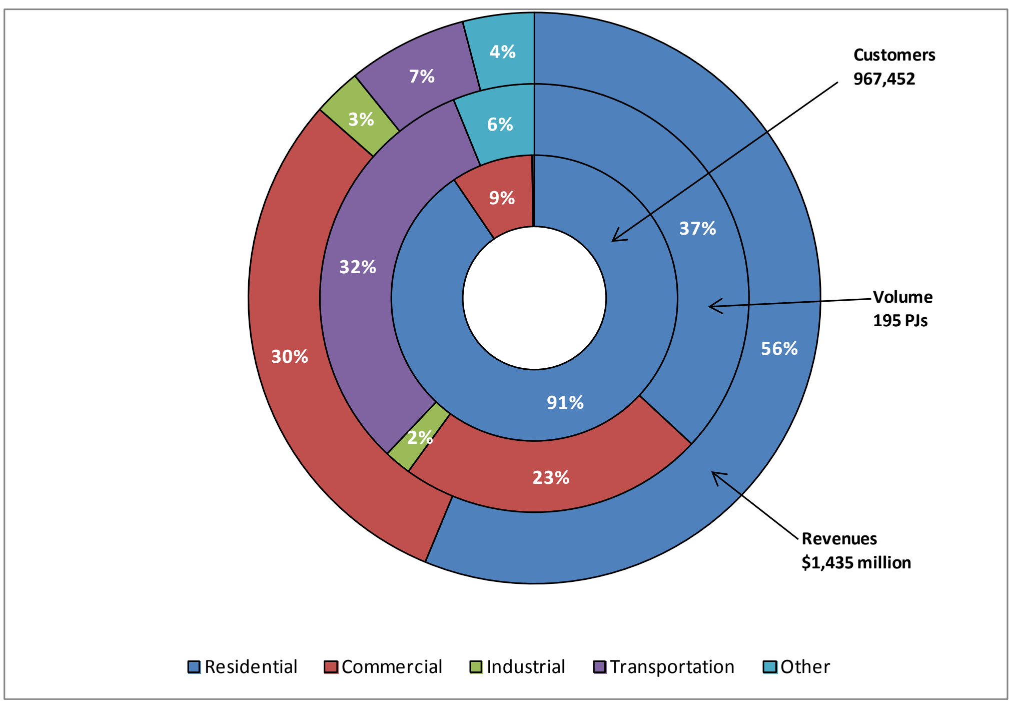
1. Operating Risks

Operating risk can be defined as the physical risks to the gas distribution system and its revenue generation potential. These risks arise from technical and operational factors, service area demographics, geography and weather. FEI is the largest distributor of natural gas in British Columbia serving approximately 970,000 residential, commercial and industrial and transportation customers in more than 125 communities across BC. The Company provides natural gas transmission and distribution to its customers and obtains natural gas supplies on behalf of most of its residential, commercial and industrial customers.

The transmission and distribution business is governed by statutes and regulated by the BCUC. FEI has agreements with a number of municipalities that are either in force or subject to renewal for as long as FEI's distribution lines are operative.[101]

It should also be noted that BC recognizes 285 different aboriginal First Nations, Bands and Tribal Councils in the province, which may lead to additional regulatory processes to allow proper recognition of these groups' rights in regulatory proceedings. This impacts the Company's business risk profile by adding the potential for protracted regulatory and political proceedings which could stymie or delay project plans and adds a layer of regulatory and administrative burden to utility operations.

Figure 7: FortisBC Energy Customer Load Profile 2014[102]



According to FEI's 2014 Annual Information Form, residential customers make up 56 percent of revenues and 37 percent of the sales volumes. Nine percent of customers are commercial customers and account for 30 percent of revenues and 23 percent of sales

[101] FortisBC Energy Inc. Annual Information Form For the Year Ended December 31, 2014 (March 13, 2015) at pp. 6-7.
[102] Ibid.

volumes. Industrial customers make up only 3 percent of revenues and 2 percent of gas sales volumes. Transport and other customers make up approximately 11 percent of revenues and 38 percent of total throughput volumes.

Below is a comparison of BC's key forward looking economic indicators in comparison to the period considered in the last GCOC proceeding. The Table shows that BC tends to follow the Canadian GDP forecast, which has declined by roughly 1.7% over the period between rate cases. Population growth is forecast to remain steady at roughly 1 percent and employment growth at close to 1 percent. Disposable income in BC tends to be slightly higher than the Canadian average and the outlook has increased over the past several years. The outlook for retail sales has also increased in both BC and Canada overall by near to 1 percent. The outlook for housing starts, however, is declining across Canada and more so in BC.

Table 12: Key Economic Indicators Projections[103]

Economic Indicator	BC 2010-2030	BC 2014-2035	Canada 2010-2030	Canada 2014-2035
GDP Growth	3.7%	2.1%	3.7%	2.0%
Population Growth	1.1%	1.0%	1.0%	1.0%
Employment Growth	0.9%	0.9%	0.8%	0.9%
Household Disposable Income	3.4%	3.9%	3.3%	3.7%
Retail Sales	2.9%	3.7%	2.9%	3.6%
Housing Starts	0.6%	(0.8%)	0.0%	(0.5%)

Overall, the Table shows that most indicators are steady to positive with the exception of GDP projections, which have fallen both nationally and for BC, and housing starts which are projected to be down for BC and for Canada as a whole.

Below is a snapshot of the long term projections for BC compared to the other Canadian provinces. As the Table shows, BC compares favorably (in the middle to upper range) to

[103] The Conference Board of Canada, Provincial Outlook 2011, Long-Term Economic Forecast 2010-2030 (January 13, 2011) and The Conference Board of Canada 2015, Long-Term Economic Forecast 2014-2035 (March 2, 2015).

the other provinces across most indicators, but lags Alberta and Ontario in population growth and employment growth. It also lags Alberta in disposable income and Ontario in housing starts. The Table reveals that FEI operates in a province characterized by positive economic, population and employment growth, and household income growth nearly at the top of all Canadian jurisdictions (the only higher is Alberta).

Table 13: Key Economic Indicators (2014-2035 Projections)[104]

Economic Indicator	NL	ALB	BC	NS	ONT	PEI	QC
GDP Growth	0.8%	2.0%	2.1%	1.1%	2.1%	1.4%	1.6%
Population Growth	(0.2%)	1.4%	1.0%	0.0%	1.1%	0.4%	0.7%
Employment Growth	(0.6%)	1.2%	0.9%	(0.1%)	1.0%	0.2%	0.5%
Household Disposable Income	1.8%	4.0%	3.9%	2.4%	3.8%	2.8%	3.0%
Retail Sales	2.3%	3.7%	3.7%	2.8%	3.7%	3.3%	3.2%
Housing Starts	(7.7%)	(1.3%)	(0.8%)	(3.5%)	1.2%	(3.3%)	(2.1%)

2. <u>Gas Supply Risk</u>

Gas supply risk relates to both the availability of gas supply and the potential for gas supply interruption. Both measures are highly dependent on the infrastructure in place to process and transport the natural gas to load centers. The risk of a supply shortfall in BC is currently deemed to be remote given the discovery of large shale reserves in northeastern BC, however, the ability to gain profitable access to markets at current price levels and with existing infrastructure may slow BC shale production. U.S. shale gas production is supplying a growing portion of eastern markets that had historically accessed gas supply from the Western Canadian Sedimentary Basin (WCSB). Overall, shale gas reserves are substantial in BC, but it is important to note that the market price for that gas must rise and new infrastructure built before these reserves will be more fully exploited.

[104] The Conference Board of Canada 2015, Long-Term Economic Forecast 2014-2035 (March 2, 2015).

According to the NEB Study of Natural Gas Deliverability in Canada, natural gas demand in Western Canada is projected to steadily increase (mostly attributable to oil sands development in Alberta), but natural gas deliverability will exceed Canadian demand (even in a low price environment where investment in the sector is less attractive).[105]

FEI relies heavily on a single pipeline, Westcoast. Though natural gas is relatively abundant in the province, there is increasing potential for price increases as access to gas at current prices may not be sustainable. In the Commission's 2013 Stage 1 GCOC Decision, it acknowledged that there was a shortage of natural gas infrastructure and though gas is abundant there is risk in being able to access gas at currently low prices. However, the Commission viewed the abundance of supply to be offset by the potential for price increase and concluded there was no material change in risk.[106]

As FEI notes in its risk evidence, the expansion of natural gas fired power demand due to the retirement of coal plants in combination with new exports of LNG, and the potential addition of new gas demand from three proposed methanol plants in Washington and Oregon, could result in a capacity shortage on Spectra's T-South pipeline to move supply to facilities in southern BC and the U.S. Pacific Northwest.[107] This capacity constraint would increase volatility and natural gas prices. While pipeline expansions are an option, they require several years to complete. Based on the projected addition of natural gas demand in BC and the Pacific Northwest and considering the availability of pipeline capacity to accommodate the incremental demand, it is my view the risks associated with pipeline infrastructure will continue to grow as incremental natural gas demand materializes.

3. Gas Price Levels and Volatility

Natural gas price volatility is an important determinant of gas distribution risk since natural gas prices compete directly with electricity in BC, and FEI's industrial customers are sensitive to fluctuations in their energy prices. Natural gas is a much more volatile

105 NEB, Short-term Canadian Natural Gas Deliverability (2014-2016) at p. 11.
106 BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at p. 39.
107 FEI Risk Appendix at pp. 30-31.

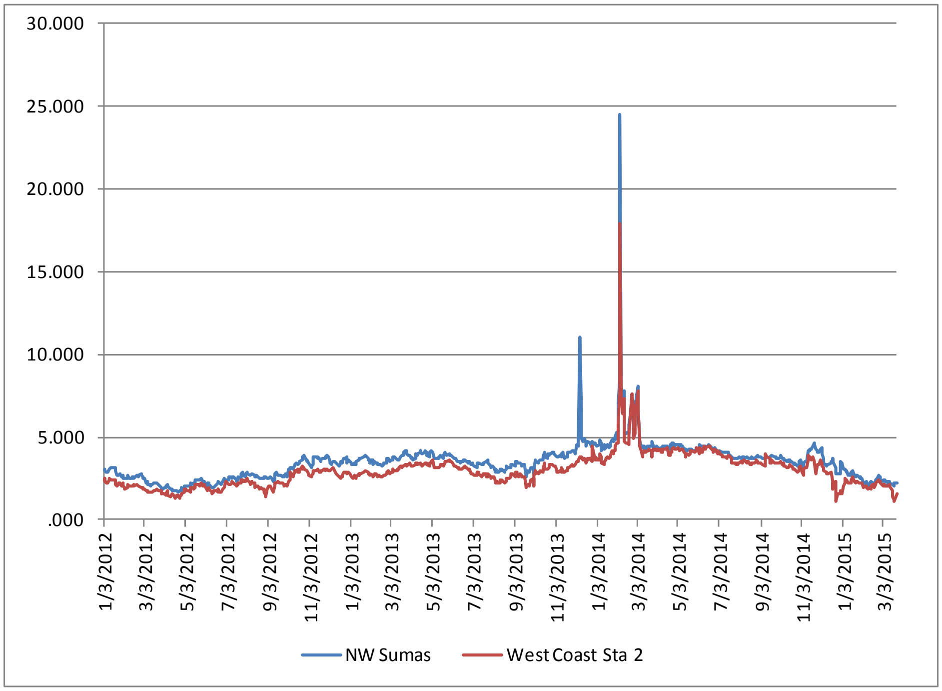
commodity in BC than electricity since the commodity cost of natural gas is market based while electricity in BC is primarily cost-based due to large provincially-owned hydro generation.

FEI contracts for approximately 138 PJ of base load and seasonal supply to serve its customers.[108] The majority of natural gas production in northern BC has served the provincial and Pacific Northwest markets via the Westcoast Spectra System, the remainder is sourced in Alberta and transported on TransCanada.[109] FEI holds approximately 35.5 PJs of storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties.[110] In the past, FEI engaged in price risk management to limit exposure to gas price volatility, which included hedging instruments, such as natural gas derivatives. In July 2011, the BCUC ordered FEI to suspend the majority of its hedging activities (except for winter Sumas/AECO basis swaps). All hedges expired in 2014.

Below are graphs of daily spot prices for the two primary trading points for West Coast pipeline and the 45-day rolling volatility (measured as the standard deviation for the most recent 45-day period) from 2012 to March 2015.

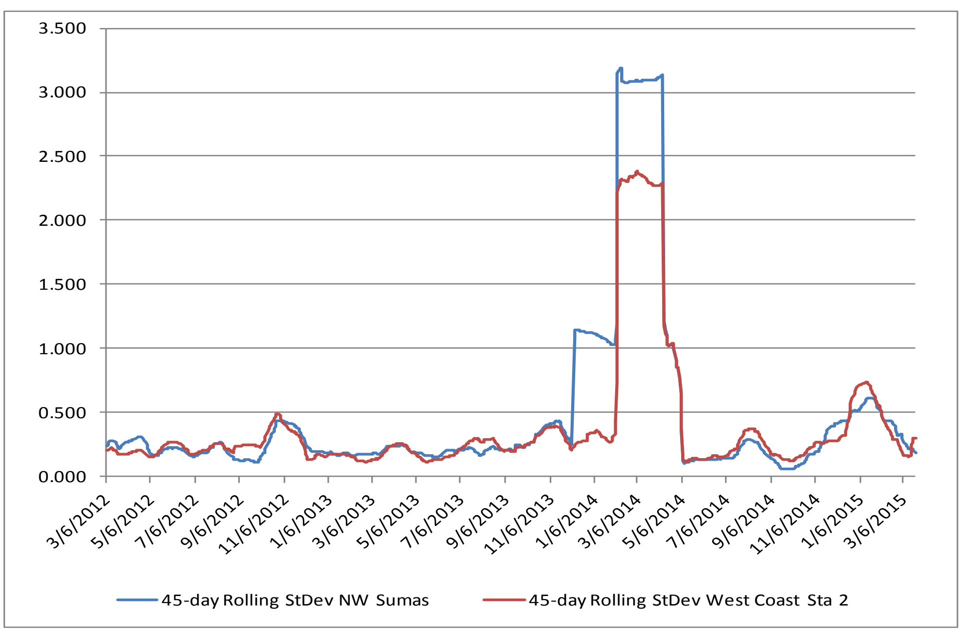
[108] Fortis Inc. 2014 Annual Information Form For the Year Ended December 31, 2014 (February 18, 2015) at pp. 19-20.
[109] Ibid.
[110] Ibid.

Figure 8: NW Sumas and West Coast Station 2 Daily Spot Prices



Source: SNL Day-Ahead Natural Gas Prices - Daily

Figure 9: 45-day Rolling Average Volatility (Measured by Standard Deviation) NW Sumas and West Coast Station 2



Source: SNL Day-Ahead Natural Gas Prices - Daily

As the figures reflect, gas prices have remained essentially the same since 2012, but volatility has increased at both pricing locations despite the increased shale production and may spike during supply shortages as seen in the winter of 2013-2014, creating price and market risk for FEI and its customers.

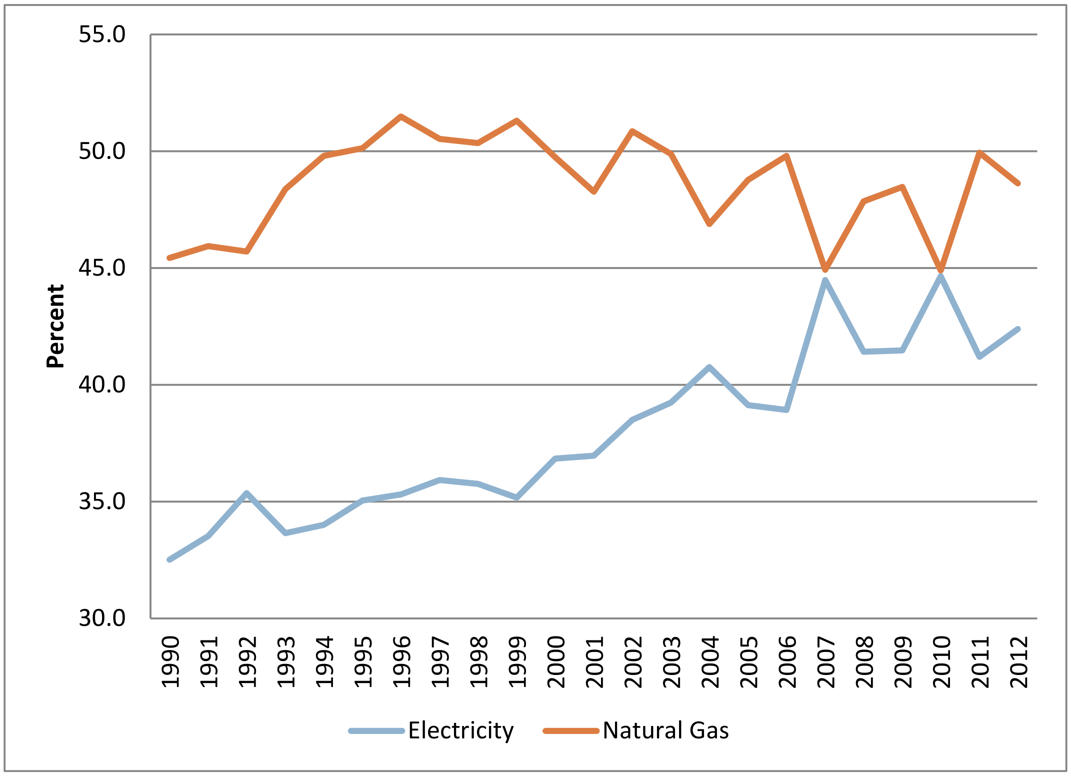
4. Volume/Demand Risk

FEI's residential and commercial sector demand is dominated by space heating and water heating, which comprise approximately 83 percent and 71 percent for each sector, respectively.[111] Together, residential and commercial space and water heating segments make up 55 percent[112] of FEI's total energy use volumes by end-use, with industrial use and transportation volumes making up the remainder. Though new customer growth is trending upward, throughput remains relatively flat,[113] indicating that use per customer continues to decline. Further, new housing starts with natural gas for space heating have continued to trend downwards with natural gas losing market share to electricity for both space heating and water heating. Today, new homes in British Columbia with gas service are less likely to use natural gas for water heating than electricity. As Figure 10 reveals, the general trend is that electricity is displacing natural gas in residential energy use. Figure 10 shows the percentages of electricity and natural gas use as a percent of total residential energy use.

111 See FEI Risk Evidence in the subject proceeding, Figure C-1, at p. 9.
112 Ibid, Figure C-2, at p. 9.
113 Ibid, Figure C-3, at p. 10.

Figure 10: Residential Energy Use for British Columbia

Natural Gas v. Electricity 1990 – 2012



Source: Natural Resources Canada, Comprehensive Energy Use Database

In addition to losing market share to electricity, housing start projections in BC have also declined over the past few years and are now projected to grow more slowly (-0.8%) than the average for Canada (-0.5).[114] All the Canadian provinces, with the exception of Ontario and Manitoba, are projecting a long term decline in housing starts.

The lower capture rate on new construction and the decline in new customer additions was raised by FEI in its evidence in the 2012 GCOC proceeding. FEI attributed this decline to the higher capital costs associated with installation of natural gas heating relative to electricity and the prevalence of new multi-family dwellings that favor electricity in terms of installation economics. In its 2013 GCOC Decision, the Commission acknowledged that the province of BC provides relatively inexpensive hydro electricity and that the competitive position of natural gas to electricity is an existing risk which

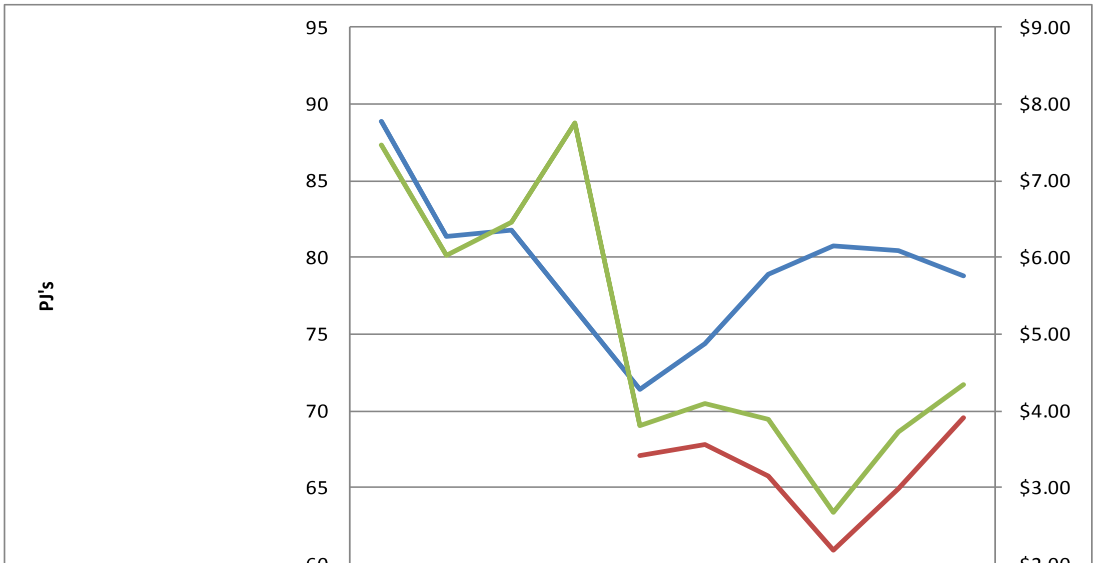
114 The Conference Board of Canada 2015, Long-Term Economic Forecast 2014-2035 (March 2, 2015).

should be reviewed at each cost of capital proceeding.[115] However, the Commission found that although use per customer was decreasing,[116] declining natural gas prices provide a competitive edge for natural gas over electricity, and any losses would be more than offset by increased industrial sales, due to low-priced natural gas. The Commission concluded that there was no evidence indicating that volume throughput risks had significantly shifted.[117]

Even though most industrial customers tend to be highly sensitive to price levels and business cycles, as Figure 11 shows, industrial throughput does not necessarily increase when prices are declining. In fact, as the figure demonstrates, industrial throughput has declined for a number of periods that were otherwise characterized by declining natural gas prices, *e.g.* 2006 and 2009; and conversely has risen in periods when gas prices have increased, *e.g.* 2007 and 2010. This demonstrates that industrial demand is influenced by a variety of factors, business cycle, technology, prices of alternative energy sources, etc. So, though gas prices are an important factor in FEI's industrial throughput, the state of the economy and business cycle as well as a number of other factors also exert significant influence over FEI's industrial throughput. The figure below reflects annual throughput total and annual average price indices at FEI's most frequent trading points, NW Sumas and West Coast Station 2. In the case of West Coast Station 2, pricing information was only available from 2009 to present.

115 BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at p. 28.
116 According to FEI's Risk Evidence submitted in this proceeding, use per customer has declined by more than 11% since 2005, which indicates a decline of greater than 1% per year. See Figure 27 on p. 45.
117 BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at p. 33.

Figure 11: Industrial Throughput and Spot Gas Prices 2005-2014



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Industrial Throughput (PJ's)	88.9	81.4	81.8	76.6	71.4	74.4	78.9	80.8	80.4	78.8
West Coast Sta 2					$3.42	$3.57	$3.16	$2.19	$2.98	$3.91
NW Sumas	$7.46	$6.03	$6.46	$7.75	$3.80	$4.10	$3.89	$2.69	$3.72	$4.33

Source: SNL Spot Natural Gas Price Indices, industrial throughput data provided by FEI.

In aggregate, FEI's use per customer is declining by greater than 1 percent per year,[118] its capture rate for new home construction and housing starts in BC are low and are projected to trend down over time; and as the figure shows, industrial throughput does not always fill in the gaps. In my opinion this presents a significant long term risk for the Company.

At present, natural gas enjoys a competitive operating cost advantage over electricity and most other fuels in the province; however, we note that the price advantage enjoyed by natural gas to electricity in BC is among the lowest in Canada, surpassed only by Quebec and Manitoba, and to a lesser extent the Maritimes and Northwest Territories where natural gas distribution infrastructure is much less prevalent. It should be noted that natural gas also competes for coal, wood, and geothermal energy in BC, which historically have been priced in proximity to retail natural gas and distribution prices. Table 14 provides a snapshot of the residential energy use for each heating source by province. Quebec is the only other major Canadian province with significant natural gas operations

[118] See Fortis Risk Evidence filed in this proceeding at p. 45.

that suffers a weaker market penetration relative to electricity than FEI. Like BC, Quebec also enjoys substantial amounts of provincially-owned, lower-cost hydroelectricity.

Table 14: Residential Energy Use by Energy Source 2012

	Natural Gas	Electricity	Heating Oil	Wood	Other
Total Canada	43%	37%	6%	12%	2%
British Columbia	49%	42%	0%	8%	1%
Atlantic	1%	42%	35%	22%	0%
Quebec	7%	64%	7%	22%	0%
Ontario	61%	24%	4%	9%	2%
Manitoba	39%	54%	0%	6%	1%
Saskatchewan	69%	25%	1%	2%	3%
Alberta	78%	18%	0%	4%	0%
Territories	7%	38%	38%	10%	7%

Source: Natural Resources Canada, Comprehensive Energy Use Database

In summary, declining use and attracting new customers will continue to present significant challenges for FEI. Though those challenges were present in 2012, FEI's loss of market share to electricity and the downturn in new housing starts, in general, threatens FEI's long-term throughput. These losses of market share to electricity are slightly mitigated by the potential to increase core services in transportation fuels and LNG expansion, but those activities are in the nascent stages and would not materially benefit FEI's throughput in the near term.[119] As FEI has stated in its Risk Evidence, "While energy price remains a driver of business risk, recent experience suggests that other non-price considerations such as GHG emissions, type of housing mix and the size of new dwellings, customer perceptions and government policy, particularly local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, (discussed in subsequent sections) are taking on greater importance in the decisions of energy consumers."[120] Overall, though these issues were all present in the last proceeding,

[119] FEI Risk Evidence in subject proceeding, at pp.13-14.
[120] FEI Risk Evidence in the subject proceeding, at p. 17.

and the company itself has not highlighted its volumetric demand risk as having significantly changed (since these risks were already present), I view demand and volumetric risk to pose unique challenges to FEI.

5. <u>Political and Regulatory Risk</u>

Political and regulatory risk relates to the potential for government or regulatory initiatives to impact gas distribution operations and revenue generation through policy, regulations, and legislation concerning tax, energy, environmental policies, industry structure, safety, reliability, and aboriginal rights. Regulatory risk may arise from the regulatory model, lagged cost recovery, allowed returns that do not satisfy the Fair Return Standard, and cost disallowances.

FEI operates in a stable and supportive regulatory environment where periodic rate proceedings allow for recovery of purchased gas costs and major capital and O&M initiatives. FEI depends on its regulatory commission to authorize returns that satisfy the Fair Return Standard and for timely recovery of prudently incurred costs. The Commission has significant discretion in carrying out its duties and in its interpretation of just and reasonable distribution rates.

FEI had been previously regulated under cost of service ratemaking from 2010-2013, but moved back to performance based ratemaking through at least 2019. PBR ratemaking poses additional risks on the regulated utility as it requires the utility to consistently achieve greater efficiencies in order to earn its allowed return. In fact, a principal objective of PBR is to de-link the relationship between costs and rates. Though FEI's PBR plan does have some moderating features, such as capital programs outside the formula mechanism and regulatory deferral accounts that are allowed flow-through treatment in the PBR mechanism, the utility remains subject to the risk that formulaic PBR rates may diverge from just and reasonable rates if, for example, productivity gains are not realized. Credit research and ratings analysts support this view. For example, in DBRS's May 2012 Industry Study, Assessing Regulatory Risk in the Utilities Sector, DBRS found incentive regulation to create more risk for the utility than cost of service ratemaking. In that Study, DBRS stated,

> "Cost-of-Service (COS) Versus Incentive Regulation Mechanism (IRM): In general, under COS, regulated utilities are allowed to recover prudently incurred operating costs and earn a reasonable return on their investment. Under IRM, revenue requirements for the year are based on a COS base year, adjusted for inflation (CPI) and minus a productivity factor (X), which is set by the regulator. This forces utilities to maintain their operational efficiency to achieve allowed ROE. DBRS views COS as lower-risk than IRM. In addition, DBRS also considers the length of an IRM period between the COS years. DBRS's scoring system gives a higher score for a shorter IRM period."

In that assessment, DBRS found that only cost of service ratemaking could earn the highest rank of "outstanding" with respect to its impact on the risk profile of the company, while incentive regulation was at best eligible for the next highest rank of "excellent" if the rate plan was less than three years, or the lower rank of "very good" if the rate plan extended four to five years, as is the case with FEI's plan. DBRS has adopted a 'wait and see' perspective with respect to FEI's rate plan. Though there was little discussion of the Plan in FEI's most recent ratings report, DBRS did note that the Plan provides for the 50/50 sharing of variances with customers arising from formula-driven expenditures over the period.[121] This 50/50 sharing of variances with customers may generally be construed as providing risk mitigation should significant variances arise under the Plan. Moody's also comments that PBR marginally increases FEI's risk due to the potential for increased cash flow volatility,[122] presumably arising from variances from formula driven O&M and base capex.

Though we do not consider FEI's PBR plan to pose a significant risk, it does create some downside risk in that it only incorporates half of new customer growth into its revenue requirement calculation and requires the company to find productivity gains annually of 1.1%. We recognize the plan provides flow-through cost recovery of variances captured through deferral and variance accounts and allows for capital cost recovery for large projects outside the PBR plan. Ultimately, negative variances arising from the Plan are shared equally with customers. As such, although the plan does introduce earnings risk, it

[121] DBRS Rating Report, FortisBC Energy Inc. (January 14, 2015) at p. 1.
[122] Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. (July 20, 2015) at p. 2.

has mitigating features that will allow for cost recovery and the sharing of downside earnings risk with customers. I consider the new PBR plan to have very little near term impact on FEI's business risk profile. However, in the later years of the Plan, as the revenue requirement is limited by I-X, the Company will be harder pressed to find productivity gains under the Plan and earnings will be exposed to greater risk.

FEI continues to operate in a political environment where climate change initiatives are at the forefront and the use of fossil fuels for water heating and space heating is discouraged, though natural gas as a transportation fuel and for LNG export is garnering some political support. Further, as FEI describes in its Risk Evidence, it is also subject to aboriginal rights issues that result in operational and regulatory complexity and a heightened risk of litigation that is particular to BC and negatively impacts FEI's political and regulatory risk environment.[123]

As FEI's risk evidence explains, BC has one of the most aggressive greenhouse gas reduction targets in Canada.[124] Major municipalities and local governments have also instituted their own initiatives by pledging their commitment to slow climate change and setting out plans to reduce greenhouse gas emissions by modifying municipal building codes and by providing incentives for alternative energy use and conservation. The carbon tax in BC serves as a deterrent to natural gas use for space heating and water heating. Though the carbon tax rate has remained constant since 2012, delivered natural gas prices to FEIs customers have increased by the addition of the tax, thereby reducing the price advantage of natural gas relative to electricity. In the Commission's 2009 Decision, it determined that the provincial government climate and energy policies had posed a changed and increased risk since it considered FEI's capital structure in 2005. The Province had passed the BC 2007 Energy Plan which aimed to reduce greenhouse gas emissions and in 2008 passed a carbon tax. The Commission found reason to believe that FEI's risk had increased as such policies would discourage the use of natural gas. However, in its most recent 2013 Decision, the Commission indicated that the risks associated with provincial government climate and energy policies were not as great as

[123] See FEI Risk Appendix, at p. 59.
[124] See FEI Risk Appendix, at p. 63.

originally thought, citing collapse of the Western Climate Initiative and the inactivity in emissions trading; and that the carbon tax had not posed a significant threat as it has remained flat at $1.50 per GJ with no plans to raise it. On this point, the Commission determined that FEI had actually become less risky than it was perceived to be in 2009.[125] In my opinion, the risks posed by climate initiatives remain at both the provincial and municipal level, and are aggressive both in a Canadian and North American context.

B. Summary

I have reviewed FEI's risk profile in terms of the five primary risk categories identified above. I have ranked FEI's risk in each area as: excellent, good, fair, challenging, or critical, with excellent being the most favorable or presenting the lowest risk, and critical presenting the greatest risk. My assessment of FEI's risk profile can be summarized as follows:

1) Operating Risks – Good - FEI operates in a province characterized by positive economic, population and employment growth, and household income growth. As shown in Table 13 previously in my testimony, BC's service territory is robust and compares favorably to the other seven Canadian provinces in my analysis, sharing very similar demographics to Ontario and Alberta (though Alberta's growth statistics are somewhat higher). FEI is the largest gas utility in BC with a large residential customer base. BC recognizes 285 different aboriginal First Nations, Bands and Tribal Councils in the province which creates operational challenges in its jurisdiction with respect to the potential for land rights claims by aboriginal groups.

2) Gas Supply and Infrastructure Risk – Good - FEI relies heavily on a single pipeline, Westcoast. Though natural gas is relatively abundant in the province, there is increasing potential for price increases, or that access to gas at current prices may not be sustainable. Growing demand for natural gas in the Pacific Northwest and

125 BCUC Decision, Generic Cost of Capital Proceeding (Stage 1) (May 10, 2013) at pp. 26-27.

limited supply infrastructure in the region could lead to deliverability constraints due to inadequate infrastructure in the region.

3) Gas Price Levels and Volatility – Fair – FEI is served primarily by the Westcoast Spectra System and the company holds approximately 35.5 PJs of storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties. Gas prices have become more volatile on the West Coast system and have tended to spike during supply shortages which ultimately factors negatively into customers' perceptions of natural gas use. Though FEI enjoys flow through recovery of gas commodity costs and generally experiences a low rate of customer bad debts, it is my experience that volatile natural gas prices and price spikes do factor into customers' perceptions of gas use and could influence fuel-switching decisions to alternative energy sources from natural gas.

4) Volume/Demand Risk – Challenging - Declining use per customer and attracting new customers will continue to present significant challenges for FEI. FEI's loss of market share to electricity and the downturn in new housing starts in general has threatened to lessen FEI's throughput, despite the prospect of attracting industrial demand with low natural gas prices (though as we saw in Figure 11, decreases in natural gas prices do not guarantee increases in industrial demand). These losses of market share to electricity are slightly mitigated by the potential to increase services in the transportation sector and through LNG expansion.

5) Political and Regulatory Risk – Challenging - FEI continues to operate in a political environment where climate change initiatives are at the forefront and the use of fossil fuels for water heating and space heating is discouraged, though natural gas as a transportation fuel and for LNG export is garnering some political support. FEI is also subject to aboriginal rights issues that impact its political and regulatory environment.

C. Relative Risks of U.S. Proxy Group and FEI

The purpose of the proxy group risk analysis is to both select companies for cost of equity analysis and determine whether any adjustments should be made to account for differences in business and financial risk between the proxy groups and FEI. In order to evaluate the comparability of the Canadian and U.S. proxy groups, I have examined the business and financial risks of each operating company relative to those of FEI. I conduct this analysis at the parent holding company level, but also review key risk parameters of each company's major North American gas distribution operating subsidiaries. In addition to the five primary areas of long-term risk discussed in the previous section, I have also reviewed the shorter-term risks associated with revenue and cost recovery uncertainty, in general, which I refer to in my analysis as "revenue stabilization" and "cost recovery". As summarized in Table 15, I have reviewed the risk profile of each publicly-traded company in the U.S. proxy group and conclude on whether that company is less risky, the same or more risky than FEI. To the extent that the risk of the proxy group is determined to be significantly different than FEI, a risk adjustment would be made to the return and/or equity ratio produced by the analyses performed.

The U.S. proxy group is screened for holding companies primarily comprised of regulated gas distribution utilities, even though some companies have higher-risk unregulated operations among the consolidated group, the weighting of these businesses are small in comparison to the regulated operations and should not have a significant bearing on the risk profile of the holding company. As indicated previously in the testimony, the screening criteria were: credit ratings of at least BBB+ from S&P, or Baa1 from Moody's; pay dividends; earnings growth rates from at least two utility industry analysts; at least 70 percent of their operating income from regulated operations in the period from 2012-2014; at least 70 percent of their regulated operating income from natural gas distribution service in the period from 2012-2014; and were not involved in a merger or other significant transformative transaction during the evaluation period. These screening criteria resulted in a comparable group of relatively pure-play U.S. regulated natural gas utilities. I have further analyzed the risk profile of each individual company relative to FEI. In my analysis, I find the U.S. proxy group is less risky than FEI. In the capital structure portion of this testimony, I evaluate whether this difference in risk warrants an adjustment to the ROE or equity ratio produced by the U.S. proxy group data. A summary of my assessment is below, and a detailed review of each U.S. proxy company can be found in the Business Risk Appendix to this testimony:

1 **Table 15: U.S. Proxy Group Risk Comparison**

				Short-term Risks		*Long-term Risks*					
Company	***Credit Rating***	***Total Assets (billions)***	***Percent Regulated***	**Revenue Stabilization**	**Cost Recovery**	**Operating Risk**	**Supply and Infrastructure Risk**	**Price and Volatility Risk**	**Volume Demand Risk**	**Political and Regulatory Risk**	**Business Risk Determination in Relation to FEI**
FEI	**A3 or A-**	**$5.9**	**100%**	**Excellent**	**Excellent**	**Good**	**Good**	**Fair**	**Challenging**	**Challenging**	
Atmos Energy	A-	$7.6	98%	Good	Excellent	Good	Excellent	Good	Good	Good	**Lower Risk**
New Jersey Resources	A	$2.8	72%	Excellent	Good	Excellent	Excellent	Excellent	Excellent	Excellent	**Lower Risk**
Northwest Natural Gas Company	A+	$3.1	89%	Excellent	Good	Good	Good	Excellent	Good	Excellent	**Lower risk**
Piedmont Natural Gas Co.	A	$3.6	97%	Good	Excellent	Good	Excellent	Excellent	Good	Excellent	**Lower risk**
South Jersey Industries	BBB+	$1.8	68%	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Good	**Comparable**[126]
Southwest Gas Corporation	A-	$4.4	94%	Excellent	Excellent	Good	Excellent	Good	Challenging	Fair	**Comparable**
WGL Holdings Inc	A+	$4.1	85%	Excellent	Excellent	Excellent	Excellent	Good	Good	Good	**Lower risk**
U.S. Proxy Group Average	**A/A-**	**$5.2**	**85%**	**Excellent**	**Excellent**	**Excellent/Good**	**Excellent**	**Excellent/Good**	**Good**	**Good**	**Lower Risk**

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[126] South Jersey was determined to be comparable in business risk due to its higher-risk unregulated operations that offsets its lower regulatory risk profile.

D. Relative Risks of Canadian Proxy Group and FEI

As previously noted, the Canadian proxy group is comprised of a small group of publicly-traded, investment grade regulated gas and electric utilities in Canada. TransCanada has been excluded from the group due to the high risk associated with the TransCanada mainline and the regulatory intervention it has received to preserve its ability to serve customers on this gas transmission line. The remainder of the publicly-traded Canadian utilities are characterized by regulated operations, spanning several regulated sectors. However, most of these utilities are substantially devoted to natural gas and electric distribution operations with either distribution company assets or distribution operating revenues exceeding 70 percent of total operations.

The one exception to this is Enbridge Inc., which in 2014 devoted only 9 percent of revenues and 13 percent of its assets to distribution operations, but had regulated revenues of 76 percent and regulated assets of 61 percent, due to the Company's extensive regulated pipeline operations. Because Enbridge's gas distribution operations, Enbridge Gas Distribution Co. in Ontario, is among FEI's closest peers; and because Enbridge Inc. is primarily engaged in regulated activities, though of a different profile than gas distribution; and endeavoring to preserve a sufficient number of proxy companies in the Canadian group, Enbridge has been retained in the group despite the differences in its risk profile from that of a gas distributor. A detailed analysis of the Canadian companies' business risks can be found in the Business Risk Appendix attached to this testimony.

Though the investor-owned Canadian utilities do not provide an ideal match to the risk profile of FEI, they do provide a reasonable point of comparison for regulated energy distribution companies primarily resident in Canada.

E. Comparison of FEI to Other Canadian Gas Distributors

I have also analyzed FEI relative to other major Canadian gas distribution companies. Table 16 lists the most recent ROE and equity ratio awards for these companies. Currently, FEI falls just above the mid-range in its weighted allowed return and equity ratio. However, the differences in risk between FEI and its Canadian counterparts suggests that FEI's ROE and equity ratio should be above that of the Canadian group.

My analysis indicates that Gaz Métro could be considered the most comparable of the Canadian gas distributors to FEI, though in my opinion Gaz Métro is more risky. I will discuss each of the below utilities in turn.

Table 16: Awarded Returns Comparable Canadian Utilities

	Credit Rating	ROE	Equity Ratio	Weighted Equity Return
FortisBC Energy Inc.	**A3 (Moody's)**	**8.75%**	**38.5%**	**3.37%**
ATCO Gas	A	8.30%	38.0%	3.15%
Enbridge Gas Distribution Inc.	A-	9.30%	36.0%	3.35%
Union Gas	BBB+	8.93%	36.0%	3.21%
Gaz Métro[127]	A	8.90%	38.5%	3.43%
AVERAGE CDN PEERS		**8.86%**	**37.10%**	**3.29%**

ATCO Gas is a gas distributor in the province of Alberta. In Alberta, the retail gas market has been restructured such that the gas supply function is subject to competition and is not regulated as part of the distributor's operations. Alberta is somewhat of a hub for natural gas transmission, and gas supply is readily available at wholesale rates. Though gas price levels and volatility factor into the competitiveness of natural gas over other competing sources of energy, natural gas in Alberta enjoys a price advantage over the next lowest priced heating fuel, electricity. In Alberta, most of the electricity generation is coal-fired which is more expensive than the legacy hydroelectricity in BC and as a result, provides a greater cost advantage to Alberta's residential gas utility customers over electricity than that which is enjoyed by the BC gas utility customers. FEI has quantified the difference in residential operating costs between natural gas and electricity to be 68 percent for Alberta and 59 percent for BC.[128] As Table 14 shows, Alberta serves 78 percent of the residential market with natural gas. Further, as shown previously in Table 13, Alberta is the fastest growing Canadian province, with population growth through 2035 projected at a rate of 1.4 percent, employment growth projected at 1.2 percent, and

[127] Gaz Metro has a 7.5 percent deemed preferred share component of its capital structure that does not require the payment of dividends to a preferred shareholder prior to the payment of common equity shareholders. As such, Gaz Metro's capital structure is effectively 46 percent equity and 54 percent debt.

[128] FEI Risk Evidence in subject proceeding, Figure C-12, at p. 23.

growth in household disposable income projected at 4.0 percent. These projections are well above those of all other Canadian provinces.

In terms of political and regulatory risk, Alberta has far less aggressive greenhouse gas targets than BC. Alberta targets 14 percent reduction in carbon emissions from 2005 levels by 2050 compared to BC, which targets an 80 percent reduction from 2007 levels by 2050. Alberta has fewer First Nations than does BC, and employs treaties to delineate land rights of aboriginal groups. Accordingly, Alberta utilities are less exposed to these risks. In terms of regulation, the Alberta Utilities Commission has historically been known for transparent and predictable regulation. It provides regulatory protection in the form of weather stabilization, load balancing, and has established a number of deferral accounts to protect the utility from uncontrollable cost fluctuations. Further, both jurisdictions have transitioned to PBR ratemaking. I generally consider the ratemaking protection in Alberta to be comparable to that of BC. Of late, however, the AUC's recent decision in its utility asset disposition ("UAD") proceeding, where it imposes a strict interpretation of the "used and useful principle" for assets in rate base, and its most recent generic cost of capital decision, which lowered ROE and equity ratios for all utilities, have reduced predictability; and in the case of the UAD Decision presents new uncertainties.

Despite the recent adverse regulatory trend in Alberta, the province's high natural gas capture rate, its strong population growth, and the lack of gas supply risk, positions Alberta at the lower end of the risk spectrum for the operation of a natural gas distribution utility in Canada. Accordingly, I consider FEI to operate in a higher risk environment than Alberta's utilities, and accordingly is higher risk than its peer, ATCO Gas.

<u>Enbridge</u> and <u>Union Gas</u> operate in Ontario. Natural Gas in Ontario enjoys a substantial price advantage over electricity due to the diverse (and costly) generation mix with the greatest share of electric load being served by nuclear, followed by hydro electricity and natural gas. Wholesale electricity prices in Ontario are set by market forces.[129] This is in contrast to BC where electric prices are determined by low embedded hydroelectric costs, ultimately providing Ontario gas utilities with a greater cost advantage over electricity than

[129] OPG has regulated rates for its prescribed nuclear and hydroelectric facilities.

in BC. FEI has quantified the difference between the residential operating costs for natural gas and electricity as being 74 percent for Ontario and 59 percent for BC, indicating that BC has an operating cost disadvantage against electricity relative to Ontario.[130]

Both Union and Enbridge operate in service territories that are robust and growing. Enbridge actually experienced an increase in customer usage from 2012 – 2014, and new customer additions are strong. The long term projection for Ontario's GDP growth is strong at 2.10 percent; and similar projections for household disposable income are also strong at 3.8 percent. Ontario has the highest long-term projection for the number of housing starts of any other Canadian province in 2015 and its capture rate for natural gas heating is high at 61 percent of the residential market. Though the Ontario utilities are providers of natural gas, they enjoy direct pass through of all commodity-related costs and operate in liquid natural gas hubs, with access to gas from Western Canada, the U.S. at Chicago, and at the Dawn trading hub in Ontario.

Like BC, the Ontario utilities operate under PBR plans that have similar regulatory protection through ratemaking where deferral accounts, revenue stabilization mechanisms and capital trackers for major projects provide the opportunity for utilities to earn their allowed returns. Ontario has aggressive greenhouse gas emissions reduction targets as does BC, with a commitment to reduce greenhouse gas emissions by 80 percent below 1990 levels by 2050. Ontario has not instituted a carbon tax as has BC and Quebec, but has recently instituted a cap and trade program for greenhouse gas emissions. Aboriginal rights issues present less risk in Ontario than in BC due to the use of treaties to delineate aboriginal rights and the lower number of aboriginal groups.

Overall, on the regulatory front, I consider Ontario and BC regulation to be comparable. But, the operating conditions in BC, including declining housing starts, lower capture rate, lower competitive margin over electricity, fewer supply options, and more exposure to aboriginal rights issues render FEI's operations higher risk than those of Enbridge Gas Distribution and Union Gas in Ontario.

[130] FEI Risk Evidence in subject proceeding, Figure C-12, at p. 23.

Gaz Métro provides 97 percent of the natural gas consumed in Quebec. Its service territory is generally less robust than BC with long-term projected GDP growth of 1.6 percent, population growth of 0.7 percent, household disposable income of 3 percent and housing starts on the decline by 2.1 percent.[131] The corresponding statistics for BC are GDP growth of 2.1 percent, population growth of 1.0 percent, household disposable income of 3.9 percent, and housing starts declining by 0.8 percent.[132] In addition, Gaz Métro is more reliant on industrial revenue, which is highly dependent on the price advantage of natural gas. Only 11 percent of Gaz Métro's throughput serves residential customers and the remainder serves commercial and industrial load.[133] In the case of FEI, 56 percent of gas distribution revenues come from residential customers.[134]

Gaz Métro is much smaller than FEI, and has the lowest price advantage over electricity of any of the major Canadian provinces due to Hydro Quebec's low supply costs. As a result, natural gas in Quebec has a low residential capture rate of only 7 percent, with electricity capturing the greatest share of the residential market at 69 percent.[135] Though Quebec has experienced an improvement in the cost advantage of natural gas over electricity due to the shale gas boom and lower-cost U.S. gas supply, this improvement will be threatened by the emphasis on carbon reduction in the Province, *i.e.* the carbon tax, a variety of greenhouse gas initiatives, and an emerging carbon market. Quebec targets reductions in greenhouse gases of 20 percent below 1990 levels by 2020. This compares to BC's commitment to reduce carbon levels by 33 percent below 2007 levels by 2020.[136] These initiatives will pose a greater risk to natural gas as opposed to electricity, since the electricity in the Province is largely supplied by no-carbon-emitting hydro-electric generation. These challenges to the competitive advantage of natural gas over electricity

131 The Conference Board of Canada 2015, Long-Term Economic Forecast 2014-2035 (March 2, 2015).
132 Ibid.
133 *See* Business Risk Appendix A to this Report *and* Valener Inc. Consolidated Financial Statements (2014).
134 FortisBC Energy Inc. Annual Information Form For the Year Ended December 31, 2014 (March 13, 2015) at pp. 6-7.
135 Natural Resources Canada, Comprehensive Energy Use Database.
136 Environment Canada, Canada's Emission Trends (October 2014), See Table A.8. *Announced GHG Reduction Targets of Provincial/Territorial governments* at p. 48.

in the Province will be more pronounced for Gaz Met, given the company's large proportion of industrial load that is dependent on the cost advantage of natural gas.

Like the Ontario utilities, Gaz Métro enjoys access to liquid natural gas trading hubs in Dawn, Ontario, a variety of U.S. supply points, and Western Canadian gas production. The Company is currently operating under a cost of service model between PBR plans. Like the other Canadian provinces, the Company enjoys regulatory support through revenue stabilization, deferral accounts and capital trackers that provide the opportunity to earn its allowed return.

Overall, I find Gaz Métro to be the riskiest of the Canadian gas distributors in my proxy group due to the low comparative advantage of natural gas over electricity, the low capture rate of natural gas in the Province, its industrial load, and its small size.

F. <u>Conclusions on Business Risk</u>

U.S. and Canadian utilities operate in similar macro-economic environments, and are governed by comparable regulatory models as analyzed in the Business Risk Appendix to this Report. The U.S. and Canadian capital markets are closely linked and move in parallel. There is a great deal of cross-border utility investment as evidenced by Fortis Inc.'s acquisitions of UNS and Central Hudson in the U.S., and Canadian and U.S. utilities compete for capital in a North American market. It is possible to select a group of U.S. utilities with comparable business risk profiles to FEI through a detailed review of each company's risks relative to FEI.

With regard to the operating companies in the U.S. proxy group, on balance, there are no fundamental differences in business risk between FEI and the U.S. proxy group that would render comparisons inappropriate. As discussed above, FEI has higher risk than the U.S. proxy group on several factors (primarily attributable to the intense competitive environment natural gas faces with electricity in the Province and the challenging environmental initiatives in BC). But FEI also faces volumetric/demand risk resulting from the downward trend in new housing starts and low capture rates for new home construction. Other factors contributing to FEI's heightened business risk profile are its

PBR plan and the associated introduction of earnings risk over the PBR term, primary reliance on a single pipeline for natural gas supply, and the additional regulatory and political complexity associated with the hundreds of aboriginal groups in the Province. One could argue that the differences in business risk between FEI and the U.S. proxy group warrant an adjustment to the ROE or capital structure produced by the U.S. proxy company data, but I have not made an explicit adjustment to the ROE for these differences in business risk.

From the perspective of establishing the allowed ROE for FEI, my view is that the U.S. proxy group (at the holding company level) is more comparable to FEI than the Canadian proxy group because it is comprised of companies that derive the majority of their operating income from and dedicate the majority of their assets to natural gas distribution service. As discussed earlier, there are few potential proxy companies in Canada, which limits the ability to select companies that are comparable to the gas distribution operations of FEI. However, as the majority of the Canadian utilities selected for the proxy group employ greater than 70 percent of their assets (or operating revenues) in energy distribution operations (except for Enbridge which devotes only 13 percent of its assets to energy distribution operations); and allowed returns for electric distributors and gas distributors are not distinguishably different, except in cases where large portions of rate base are dedicated to electric generation, the Canadian proxy group reasonably informs my analyses and adds value by providing a Canadian perspective. Accordingly, I have relied equally on the results of the U.S. and Canadian proxy groups in the return on equity analyses.

My specific conclusions with respect to FEI's risk relative to the U.S. proxy group, the Canadian proxy group and its risk compared to other Canadian gas distributors is as follows:

- The U.S. proxy group is less risky than FEI, but not to a degree that warrants a risk adjustment to the ROE.
- The majority of Canadian utilities selected for the proxy group employ greater than 70 percent of their assets (or operating revenues) in energy distribution operations (except for Enbridge which devotes 13 percent of its assets to energy distribution

operations). Though the investor-owned Canadian utilities do not provide an ideal match to the risk profile of the benchmark natural gas distributor in BC, they do provide a reasonable point of comparison for regulated energy distribution companies primarily resident in Canada.

- FEI is generally more risky than other major natural gas distributors in Canada except for Gaz Métro, which is determined to be higher risk than FEI.

G. <u>Financial Risk Factors</u>

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 credit crisis and financial market disruptions of 2008 and 2009. The equity in the capital structure, besides providing a return that compensates equity shareholders for their investment, serves to buffer unanticipated earnings swings. If the equity layer becomes too thin, lenders will become concerned that the company may not be able to meet its fixed debt obligations, and will require a higher debt 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 will 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.

Financial risk is assessed in terms of credit metrics, credit rating, capital structure, and authorized return. (Capital structure and authorized return span both major risk areas, *i.e.* regulatory and financial risk.) Credit metrics provide a snapshot of how the company is financed and to what extent fixed obligations absorb income and cash flows. Credit analysts focus on the potential for default on debt obligations and rate the financial strength of the companies they cover, with A being a strong credit, and anything less than investment grade, *i.e.* BBB- (for S&P, DBRS and Fitch), or Baa3 (for Moody's), a risky credit rating. It is important to note ratings agencies analyze the default risk for *debt holders* 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 that punctuate that credit rating is not always a good measure of shareholder risk, *e.g.* where credit rating is supported at the expense of shareholders, thereby lowering risk to creditors but increasing risk to shareholders.[137]

Ratings agencies and financial analysts look to several credit metrics to assess the financial wherewithal of a utility. Moody's assigns 40 percent of its overall credit rating determination for a given company based on financial strength and key financial metrics. The remaining 60 percent is assigned as follows: regulatory framework (25 percent), ability to recover costs and earn returns (25 percent), and diversification (10 percent). For a gas or electric distribution company, Moody's relies on four primary credit metrics:

- Funds flow from operations (FFO) interest coverage ratio,
- FFO to debt ratio,
- Retained cash flow (FFO less dividends) to debt ratio, and
- Debt to capital ratio.[138]

Interest coverage ratios are important to assessing financial risk as they provide insight into the magnitude of the company's fixed cost obligations and the extent to which earnings exceed those obligations. Cash flow based metrics (as opposed to earnings based metrics) reflect the cash reality of the business, where earnings may not, due to

[137] *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."

[138] Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities (December 23, 2013) at p. 24.

capitalization of costs, non-cash charges or income, and dividend payments. Cash flow metrics are particularly important for a regulated utility due to the capitalization of regulatory assets, *i.e.* capitalizing costs that would otherwise be expensed, such that costs are spread over the period of future rate recovery.

S&P relies on cash flow/leverage analysis to determine the financial risk profile of a company. Financial risk is combined with business risk in accordance with a risk matrix to determine the basic risk of an entity (before any special adjustments). For example, a company with excellent business risk and significant financial risk would have an anchor risk assessment of A-. S&P then applies modifiers to its anchor assessment to assess the overall credit risk of a company. Its modifiers include: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. These modifiers can change the credit rating up or down in small increments. S&P calculates two core credit ratios, FFO to debt and debt to EBITDA, which they compare to benchmarks to assess the cash flow leverage of the company. S&P also uses supplemental ratios to either confirm or adjust a preliminary cash flow leverage assessment. The five standard supplemental ratios that S&P relies upon are:

- Cash flow from operations (CFO) to debt,
- Free operating cash flow (FOCF) to debt,
- Discretionary cash flow (DCF) to debt,
- FFO plus interest to cash interest,
- EBITDA to interest.[139]

Moody's provides the following guidelines for the four key credit metrics to be used in a low business risk scenario (which is appropriate for FEI and the U.S. proxy companies, and the Canadian gas distribution operating companies):

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

Table 17: Moody's Four Key Financial Strength Metrics[140]

	Investment Grade				Non-Investment Grade		
Metric	**Aaa**	**Aa**	**A**	**Baa**	**Ba**	**B**	**Caa**
CFO pre-WC + Interest/Interest	≥ 8x	6x-8x	4.5x-6x	3x-4.5x	2x-3x	1x-2x	< 1x
CFO pre-WC/Debt	≥ 38%	27 – 38%	19-27%	11-19%	5-11%	1-5%	< 1%
CFO pre-WC – Dividends/Debt	≥ 34%	23 – 34%	15-23%	7-15%	0-7%	(5%)-0	< (5%)
Debt/Capitalization	< 29%	29 – 40%	40-50%	50-59%	59-67%	67-75%	≥ 75%

Moody's notes in its credit rating report that FEI's financial position is weak and provides limited headroom at the current rating. It goes on to note that large capital projects will place additional pressure on FEI's financial metrics.[141] Indeed, reviewing the Moody's guidelines in the previous Table, we see that FEI's regulatory deemed debt to capital ratio of 61.5 percent, would not be sufficient for an investment grade credit rating of Baa or higher. Though Moody's does not evaluate FEI's financial metrics on a deemed basis, the point is that a debt/capitalization ratio of greater than 59 percent would generally not be sufficient to achieve an investment grade credit rating, let alone an A rating.

The following Table below reflects the proxy group metrics at the holding company level, based on published financial statements. These metrics are calculated in accordance with standard calculation methodologies and though are aligned with the Moody's guidelines listed above, there are differences from what Moody's or S&P would calculate because of the adjustments each ratings agency makes to their credit metrics. The credit metrics I have calculated are as follows:

140 Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities (December 23, 2013) at 24, where "CFO pre-WC" is "Cash Flow from Operations Before Changes in Working Capital"; "CFO pre-WC + Interest/Interest" is "CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage"; "CFO pre-WC/Debt" is "CFO Pre-Working Capital/Debt"; and "CFO pre-WC – Dividends/Debt" is "CFO Pre-Working Capital Minus Dividends / Debt".

141 Moody's Investors Service, Credit Opinion, FortisBC Energy Inc. (July 20, 2015).

- EBIT/Interest - Net income before interest paid and accrued and before provision from income taxes, divided by interest paid and accrued (higher coverage is stronger);
- FFO/Interest - Cash flow from operations before changes in working capital and before effects of AFUDC, divided by interest paid and accrued (higher coverage is stronger);
- FFO/Debt - Cash flow from operations before changes in working capital and before effects of AFUDC, divided by the aggregate long and short-term unpaid principal balance owed under financial obligations to other parties, required to be paid by a specified date or on demand (a higher percentage is stronger);
- Debt/Capital - Aggregate long and short-term unpaid principal balance owed under financial obligations to other parties, required to be paid by a specified date or on demand, divided by total book capitalization (total debt plus total equity, plus current portion of preferred equity, plus total Mezzanine level items) (a lower percentage is stronger); and
- Debt/EBITDA - Aggregate long and short-term unpaid principal balance owed under financial obligations to other parties, required to be paid by a specified date or on demand, divided by net income before interest paid and accrued, before provision for income taxes, and before depreciation, depletion and amortization associated with operations (a lower value is stronger).

1 **Table 18: Proxy Group Credit Metrics[142]**

	Credit Rating	EBIT/ Interest	FFO/ Interest	FFO/ Debt	Debt/ Capital	Debt/ EBITDA
FortisBC Energy Inc.	**A3[143]**	**1.94x**	**1.48x**	**12%**	**49%**	**4.18x**
U.S. Proxy Group						
Atmos Energy Corp.	A-	4.63x	5.97x	29%	46%	3.08x
New Jersey Resources	A	8.27x	10.29x	29%	49%	3.43x
Northwest Natural Gas	A+	3.40x	5.15x	24%	54%	4.01x
Piedmont Natural Gas	A	4.19x	6.11x	24%	58%	4.32x
South Jersey Industries	BBB+	3.85x	4.64x	13%	57%	6.45x
Southwest Gas Corporation	BBB+	3.98x	6.20x	27%	53%	3.05x
WGL Holdings, Inc.	A+	5.36x	10.77x	35%	47%	3.68x
U.S. Average	**A**	**4.81x**	**7.02x**	**26%**	**52%**	**4.00x**
Canadian Proxy Group						
Canadian Utilities	A	3.25x	4.31x	22%	57%	4.18x
Emera, Inc.	BBB+	3.96x	3.83x	18%	52%	3.68x
Enbridge Inc.	A-	2.14x	2.76x	12%	66%	7.37x
Valener Inc.	BBB+	28.32x	26.74x	69%	9%	1.37x
Fortis Inc.	A-	1.74x	1.95x	10%	56%	6.84x
Canadian Average[144]	**A-**	**2.77x**	**3.21x**	**16%**	**58%**	**5.52x**
Overall Proxy Group Average	**A-**	**4.07x**	**5.63x**	**22%**	**54%**	**4.55x**
Canadian Gas Distributors						
ATCO Gas	A	3.17x	5.12x	27%	55%	3.96x
Enbridge Gas Distribution Inc.	A-	2.34x	3.28x	13%	63%	6.51x
Union Gas Limited	BBB+	2.42x	2.63x	13%	70%	5.27x
Gaz Métro Limited Partnership	A	2.43x	3.81x	19%	68%	5.05x
Canadian Distributors Average	**A-**	**2.59x**	**3.71x**	**18%**	**64%**	**5.20x**

2

142 Source data from SNL Financial as available for 2014; otherwise regulatory financial packages were used for 2014.

143 Note that FEI is not rated by S&P, but is rated A3 by Moody's, which from a ratings scale perspective is roughly equivalent to S&P's A- rating. Each company considers and weights factors differently in their ratings determinations and an A3 rating by Moody's would not necessarily result in an A- rating by S&P.

144 The Canadian Average excludes Valener Inc. as an outlier for all credit metrics. Valener is structured as an equity partnership and has little debt in its holding company structure except that which has been issued by Gaz Metro.

As Table 18 shows, FEI has the weakest cash flow metrics and earnings metrics of any of the proxy companies. The only exception to this is Fortis Inc. (its parent) with a slightly lower EBIT/Interest coverage ratio and FFO/Debt ratio. There are many elements at the Holdco level that effect earnings, debt levels, cash flows, and the credit metrics of the Holdco. For these reasons, in my opinion, the comparisons between FEI and the Canadian gas distributor peer group - a group of Canadian operating companies are most relevant. Compared to the Canadian Gas Distributors group, FEI is comparably rated by the credit rating agencies, but has a weaker EBIT/Interest coverage ratio, a weaker FFO/Interest coverage ratio and a weaker FFO/Debt ratio than its Canadian peers. Only FEI's Debt/Capital and Debt/EBITDA ratios are stronger than its Canadian Gas Distributor peers. FEI has weaker credit metrics than the U.S. proxy group across all metrics, including credit rating. FEI compares similarly to the Canadian proxy group as it does to the Canadian gas distributors peer group.

In the following Table, we analyze FEI's financial risk since 2012, using Moody's credit metrics.[145] In 2013, Moody's reported a negative ratings trend due to the expected further weakening of FEI's financial metrics, due to "the BCUC's generic cost of capital decision, which reduced both FEI's allowed ROE level and equity component for rates".[146] However, in 2014, Moody's revised the outlook to "Stable", based on the "expectation of a stable regulatory environment and stable, albeit weak financial metrics with ongoing limited headroom."[147] As indicated in Table 19, FEI's credit metrics have remained relatively constant despite its lower deemed equity ratio and ROE. Though FEIs credit metrics may be influenced by a number of factors, this result is at least partially due to the higher authorized returns attributed to FEVI and FEW that transitionally flow into FEI's earnings in the current period. The ROE decided in this proceeding will not differentiate the returns of FEI, FEVI and FEW, as FEI will receive one return for the amalgamated companies.

145 FEI is rated by Moody's and DBRS credit ratings analysts.
146 Moody's Credit Opinion: FortisBC Energy Inc. (June 26, 2013).
147 Moody's Credit Opinion: FortisBC Energy Inc. (July 15, 2014).

Table 19: FEI Financial Metrics 2012 - Q1 2015

	3/31/2015 (L)	2014	2013	2012	Rating	Increase/ Decrease in Risk
Credit Rating – Moody's	A-3/Stable	A-3/Stable	A-3/Neg.	A-3/Stable	---	Same
Authorized Return	8.75%	8.75%	8.75%	9.50%	---	Increased
Deemed Equity Ratio	38.50%	38.50%	38.50%	40.00%	---	Increased
CFO pre-WC+Interest/Interest	2.8x	2.8x	2.7x	2.5x	Ba	Decreased
CFO pre-WC/Debt	15.0%	14.4%	15.1%	14.5%	Baa	~Same
CFO pre-WC-Dividends/Debt	9.1%	10.3%	8.0%	9.6%	Baa	~Same
Debt Capitalization	44.8%	45.2%	43.6%	44.0%	A	~Same

Source: FEI Annual Reports 2011, 2014; and Moody's Credit Opinion: FortisBC Energy Inc. (July 20, 2015) Note: credit metrics, as published by Moody's incorporate the effects of amalgamation.

Though the transitional effects of amalgamation are helping FEI's financial risk profile in the short term, even with the benefit of higher returns and equity returns from FEVI and FEW, FEI's credit metrics do not fall within Moody's guidelines for the A rating category. As the former rate base associated with the amalgamated entities FEVI and FEW transition to FEI's lower equity ratio and allowed return as of January 1, 2015, all else being equal, the amalgamation is expected to reduce FEI's credit metrics.

FEI has planned regulated capital additions over the next few years totaling approximately $1.69 billion. This is in addition to its normal capex determined by the PBR capex formula of approximately $150 million plus annually.[148] Making up the $1.69 billion is the approximate $250 million of costs associated with the Lower Mainland Intermediate Pressure System Upgrade to replace sections of pressurized pipeline segments in the Greater Vancouver area expected to be in service in 2018;[149] $600 million of costs associated with the Woodfibre LNG Pipeline Expansion which expands compression and

148 FEI workshop presentation, FEI Annual Review of 2015 Rates (March 6, 2015) at p. 22.
149 FortisBC Energy Inc. MD&A (December 31, 2014) at p. 6.

pipeline capacity to the Woodfibre LNG site expected to be operational in 2018,[150] $440 million for the Tilbury LNG Expansion Project Phase 1A for a new LNG storage tank and liquefier to be in service by the end of 2016,[151] and an estimated $400 million investment for the potential further expansion of the Tilbury LNG facility.[152] In total, if FEI finances these projects in accordance with its deemed capital structure, it will require approximately $1 billion of new debt financing over the next several years.

All else being equal, downward pressure on FEI's credit metrics related to higher capex spending in the near term may result in downward pressure on FEI's credit rating and could result in a ratings downgrade, since FEI operates at the lowest rung of the A rating (A3). Though in Moody's assessment, a ratings downgrade is unlikely, it indicates that there are several factors that could lead to a downgrade; examples provided were: "an unexpected, material adverse regulatory decision or a forecast of a sustained deterioration in credit metrics including CFO/pre-W/C to debt of less than 11%."[153] Moody's currently calculates FEI's CFO/pre-W/C to debt metric at 15.0% for FEI at March 31, 2015.[154]

A downgrade below an A rating grade is particularly important in the Canadian credit market where there is less trading of lower-rated investment grade debt (*i.e.* below the A ratings grade). Institutional investors often face limits or are precluded from investing in Baa/BBB debt. Further in the financial market dislocation of 2008 and 2009, regulated issuers below an "A" credit rating, were effectively shut out of the Canadian credit market.[155] In the Commission's last ROE Decision, it acknowledged the desirability for utilities to maintain an "A" category credit rating, but also expressed that this goal not be pursued at all costs.[156] However, in light of FEI's large capex program and its upcoming

150 Fortis Inc. MD&A (December 31, 2014) at p. 9.
151 FortisBC Energy Inc. MD&A (June 30, 2015) at p. 7.
152 FortisBC Energy Inc. MD&A (December 31, 2014) at p. 5. Note this Phase 1B Expansion is contingent on a requirement that the additional capacity is 70 percent contracted over the first 15 years of operation before construction on the project may begin.
153 Ibid.
154 Ibid.
155 See AltaLink 2011-2013 GTA Decision 2011-453, paragraph 798, where the Alberta Commission states: "A list of individual debt transactions provided by AltaLink shows that during the period June 11, 2008 to January 29, 2009, companies with credit rating outside of an A category were not able to issue long-term debt on any terms in the public Canadian debt market."
156 BCUC Generic Cost of Capital Decision, Stage 1 (May 10, 2013) at p. 50.

financing requirements, a downgrade to below an A rating would result in substantially higher financing costs and should be avoided. In its most recent credit opinion, Moody's expresses that FEI has limited financial headroom at the current rating and that large capex as well as the amalgamation will place downward pressure on FEI's credit metrics. Specifically, Moody's states:

> The company is forecast to have limited financial metric headroom at the current rating. Planned large capital projects are expected to place some downward pressure on credit metrics; for example, the Tilbury LNG Expansion Project (Tilbury 1A) with a capital cost of about C$440 million because depreciation cash flow will not begin until this project is in operation. In addition, the amalgamation will place some modest downward pressure on financial metrics as the company unwinds a regulated liability in 2015 and 2016. As a result, we forecast that credit metrics will decline somewhat in 2015 and improve as capital projects are completed in 2016-17.[157]

So, as FEI adds capex spending, it will become increasingly important to allow adequate financial flexibility such that FEI will maintain its A3 credit rating and withstand unexpected and adverse earnings impacts that could negatively affect credit metrics and cash flows, and consequently threaten its credit rating and its ability to access capital. Utilities require access to capital in all market environments and business cycles and accordingly it is important to provide ample credit support such that the utility can attract capital on reasonable terms.

In terms of financial risk, my conclusion is that FEI has similar but higher financial risk to the companies in the Canadian proxy group and higher financial risk than the companies in the U.S. gas distribution proxy group. Its credit metrics are weak and do not meet the guidelines of Moody's A-rated regulated utility. Its capex spend will continue to put pressure on its financial metrics highlighting the importance of an authorized return and equity ratio that will allow FEI to continue to maintain a Moody's credit rating of no lower than A3 over the period that rates will be in effect.

157 Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. (July 20, 2015) at p. 3.

H. Risk Analysis Conclusions

Based on the results of the risk analysis, my conclusions are as follows:

- The economic conditions and business environments in Canada and the U.S. are similar enough that investors would not require materially different returns on equity from companies that were otherwise comparable;
- FEI has greater business risk than the U.S. proxy group companies, and greater financial risk than both the U.S. and Canadian proxy group companies;
- FEI has higher business risk than the peer group of Canadian gas distributors, except for Gaz Métro, due to competition with electricity prices in BC, its low capture rate, the decline in single family housing in BC, strict regulations on carbon emissions in BC that aim to reduce natural gas consumption, and the regulatory risk around aboriginal land rights. Likewise, FEI has higher long-term business risk than the U.S. proxy group on several of these same factors.
- FEI's ROE and equity ratio are comparable to its Canadian gas distribution peer companies, despite its higher risk.
- Through amalgamation, FEI has increased its size but since it was already a large gas distributor, there has been no impact on FEI's risk profile due to the increased size of the amalgamated entity.

I carry these conclusions into my recommendations on capital structure.

VII. CAPITAL STRUCTURE

Capital structure and the cost of common equity are closely linked in determining the fair return for regulated utilities. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks in the form of financial leverage to which their shareholders are exposed. Accordingly, regulators must consider capital structure in the establishment of a fair return on common equity.

FEI is proposing a deemed capital structure consisting of 40.0 percent common equity and 60.0 percent long-term debt, a slight increase in equity over the 38.5 percent equity and 61.5 percent debt authorized in the last GCOC Decision. In that proceeding, the Commission cited the following reasons for reducing FEI's equity ratio:

> The Commission Panel is supportive of maintaining an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.[158]

Table 20 presents a compilation of all Canadian and U.S. peer group companies according to credit rating, authorized ROE and equity ratios in relation to Concentric's overall risk assessment for FEI. As shown in Table 20, FEI is ranked in the 44th percentile for credit rating (lower half), is determined to be slightly more risky than the entire group, and is in the lower quartile for allowed equity ratio and return. Even at FEI's proposed capital structure and ROE recommendation, its weighted equity return remains in the bottom quartile of all of the proxy group companies.

[158] BCUC GCOC (Stage 1) Decision (May 10, 2013) at p. iii.

Table 20: Comparative Risk Analysis – U.S. and Canadian Gas Distributors

Operating Company	Credit Rating	Risk Assessment relative to FEI	Authorized Equity Ratio	Authorized Return	Weighted Equity Return
Proposed FortisBC Energy Inc.	**A-**		**40.0%**	**9.50%**	**3.80%**
FortisBC Energy Inc.	**A-**		**38.5%**	**8.75%**	**3.37%**
ATCO Gas	A	less risky	38.0%	8.30%	3.15%
Enbridge Gas Distribution Inc.	A-	less risky	36.0%	9.30%	3.35%
Union Gas	BBB+	less risky	36.0%	8.93%	3.21%
Gaz Metro	A	more risky	38.5%	8.90%	3.43%
Atmos Energy Inc.					
Mid-Tex Cities SOI & Environs	A-	less risky	52.0%	10.50%	5.46%
Atmos Colorado	A-	less risky	52.0%	9.72%	5.05%
Atmos Kansas	A-	less risky	53.0%	9.10%	4.82%
Atmos Tennessee	A-	less risky	51.0%	10.10%	5.15%
Atmos Virginia	A-	less risky	54.0%	9.75%	5.27%
Atmos Louisiana	A-	less risky	51.0%	9.80%	5.00%
Atmos Mississippi	A-	less risky	55.0%	9.98%	5.49%
Atmos Kentucky	A-	less risky	49.0%	9.80%	4.80%
New Jersey Resources					
New Jersey Natural Gas	A	less risky	51.2%	10.30%	5.27%
Northwest Natural Gas Company					
Northwest Natural Gas Company - Oregon	A+	less risky	50.0%	9.50%	4.75%
Northwest Natural Gas Company - Washington	A+	less risky	51.0%	10.10%	5.15%
Piedmont Natural Gas Co., Inc.					
Piedmont Natural Gas Co., Inc. - North Carolina	A	less risky	50.7%	10.00%	5.07%
Piedmont Natural Gas Co., Inc. - South Carolina	A	less risky	55.0%	10.20%	5.61%
Piedmont Natural Gas Co., Inc. - Tennessee	A	less risky	52.7%	10.20%	5.38%
South Jersey Industries, Inc.					
South Jersey Gas Co.	BBB+	comparable	51.9%	9.75%	5.06%
Southwest Gas Corporation					
Southwest Gas - Arizona	A-	comparable	52.3%	9.50%	4.97%
Southwest Gas - Northern Nevada	A-	comparable	59.1%	9.30%	5.50%
Southwest Gas - Southern Nevada	A-	comparable	42.7%	10.00%	4.27%
Southwest Gas - California	A-	comparable	55.0%	10.10%	5.56%
WGL Holdings Inc.					
Washington Gas - Maryland	A+	less risky	53.0%	9.50%	5.04%
Washington Gas - DC	A+	less risky	59.3%	9.25%	5.49%
Washington Gas - Virginia	A+	less risky	59.6%	9.75%	5.81%
Average Canadian Gas Distribution Peers	**A-**	**less risky/comparable**	**37.1%**	**8.86%**	**3.29%**
FEI Current Percentile Rank Among Canadian Utilities	***67%***	***less risky/comparable***	***100%***	***25%***	***75%***
FEI Proposal Rank Among Canadian Utilities	***67%***	***less risky/comparable***	***100%***	***100%***	***100%***
Average U.S.		**less risky**	**52.8%**	**9.83%**	**5.18%**
FEI Current Percentile Rank Among U.S. Utilities	***43%***	***less risky***	***0%***	***0%***	***0%***
FEI Proposal Percentile Rank Among U.S. Utilities	***43%***	***less risky***	***0%***	***0%***	***0%***
Average All Proxy Companies		**less risky**	**50.3%**	**9.68%**	**4.89%**
FEI Current Percentile Rank Among All Proxy Utilities	***44%***	***less risky***	***12%***	***3%***	***9%***
FEI Proposal Percentile Rank Among All Proxy Utilities	***44%***	***less risky***	***13%***	***28%***	***14%***

Current capital market conditions, though having improved somewhat from the economic disruption of the global financial crisis in 2008-2009, are still uncertain and advanced economies continue to institute protective and stimulative measures to provide economic stability. Utilities are highly dependent on capital resources to support their infrastructure requirements and must access capital markets in all business cycles, good and bad. Financial headroom (or a sizeable financial buffer) over fixed obligations will provide assurance to creditors and shareholders that the utility will be able to meet its debt obligations, regardless of the business cycle and capital market environment, which in turn will translate to better credit metrics and lower capital costs.

In the context of current capital market conditions, I find FEI's proposed capital structure to be appropriate, albeit conservative. The proposed equity ratio of 40 percent recognizes the greater risks of FEI relative to its Canadian peer companies; only Gaz Métro is riskier than FEI, and Gaz Métro enjoys a substantial portion of deemed preferred equity, effectively acting as a further buffer for debt holders. With respect to the U.S. proxy group, FEI's proposal would fall below the entire range of U.S. companies, *i.e.* no U.S. company had either an equity ratio of 40.0 percent or below; or had a weighted equity ratio of 3.80 percent or below. On that basis, I believe that FEI's proposed equity ratio of 40.0 percent is conservative because of its higher risk.

As shown in Exhibit JMC-9, if the estimated cost of equity for the U.S. gas distribution proxy group were adjusted to reflect the difference between FEI's equity ratio and the average equity ratio for the U.S. proxy group, it would result in an upward adjustment ranging from 95 to 119 basis points to the range of U.S. proxy group ROE results. Although I have not proposed an adjustment in this proceeding for the difference in capital structure between FEI and the U.S. proxy group, my view is that the higher financial risk of FEI should be considered relative to the U.S. gas distribution companies. I therefore find the Company's proposed capital structure to be appropriate in the context of today's capital market environment and the substantial upcoming capital requirements FEI will be facing as it executes its capex plan; and is supported by the evidence presented.

VIII. AUTOMATIC ADJUSTMENT MECHANISM

In its last Generic Cost of Capital Proceeding, the Commission re-instituted an Automatic Adjustment Formula to estimate the benchmark ROE between cost of capital proceedings. The Commission instituted a two variable model, based on long Canada bond yields and the spread between long Canada bonds and A-rated utility corporate bonds. The new formula does not go into effect until the actual long Canada bond yield meets or exceeds 3.8 percent, in recognition that there is an atypical relationship between ROE and cost of risk in periods of unusually low interest rates. The formula base ROE was determined to be 8.75 percent. The model is given by the following formula:

$$ROE_1 = \text{Base ROE } (8.75\%) + 0.50 \text{ x } (LCBF_t - BaseLCBF) + 0.50 \text{ x } (UtilBondSpread_t - BaseUtilBondSpread)$$

Where:

$LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent;

Base LCBF is 3.8%;

$UtilBondSpread_t$ is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields;

and BaseUtilBondSpread was determined to be 1.342.

Though an evidentiary review of a given utility's cost of capital is most likely to provide the most accurate estimate of a utility's cost of equity, and an AAM formula with limited inputs cannot capture all of the factors that might impact the ROE estimation, in my opinion, if the Commission continues to use an AAM beyond the initial two-year term of the current AAM, it should continue to use the two factor model to capture corporate credit conditions as well as the level of prevailing risk free bond rates.

IX. OVERALL CONCLUSIONS AND RECOMMENDATIONS

As discussed in greater detail in Section VI, I have analyzed the risks of a carefully-selected proxy group of U.S. gas distribution companies and compared those risks to the risks of FEI. I have also included evidence concerning a Canadian proxy group.

As seen in Table 21, the results from the alternative models cover a range from 8.89% (U.S. Multi-Stage DCF) to 12.70% (Canadian, Constant Growth DCF). Within this range, an equal weighting of all methods with both Canadian and U.S. proxy groups would produce an average of 10.04% but one must give consideration to the appropriate weights placed on each method and proxy group. Consistent with the Hope decision, it is the end result and not the method that is determinative of a fair return.

Table 21: Summary of Results (including 50 bps flotation costs)

	Canadian Utility Proxy Group	U.S. Gas Distribution Proxy Group	Average
CAPM	9.08%	10.08%	**9.58%**
Constant Growth DCF	12.70%	9.68%	**11.19%**
Multi-Stage DCF	9.82%	8.89%	**9.36%**
Average	**10.54%**	**9.55%**	**10.04%**

The evidence indicates that a carefully selected group of U.S. proxy companies is more like FEI than the Canadian proxy companies due to their business profiles, but because of the importance of a Canadian perspective, I have given them equal weight in my recommendation. The U.S. proxy group is based on a careful screening of the universe of U.S. companies to select those most comparable to FEI. That screening process considers factors such as credit ratings, payment of dividends, availability of growth rate estimates, and the extent to which the company is engaged in regulated natural gas distribution operations. Importantly, the credit ratings for the U.S. gas distribution proxy group are between BBB+ and A+, similar to FEI's rating of A3 from Moody's (equivalent to Standard and Poor's A-). By choosing U.S. proxy group companies with similar credit ratings to FEI, the proxy group is comprised of similar-risk utilities with comparable business and financial risks, as indicated by those credit ratings.

Turning to the choice of models, I understand the BCUC has placed varying weights on the DCF and CAPM. In its 2009 Terasen Gas decision, the Commission gave the most weight to the DCF approach, and lesser to the ERP and CAPM approaches.[159] In the 2013 GCOC Decision, the Commission placed equal weight on the DCF and CAPM.[160] I similarly have placed equal weight on the DCF and CAPM model as the basis for the recommended ROE for FEI.

Based on the results of the analyses discussed above and throughout my testimony, I have reconciled for current market conditions in my selection of inputs to the CAPM analysis to address concerns with the ability of the CAPM model to produce reasonable results in light of the factors affecting the inputs at this time. Bond yields in Canada and the U.S. have been driven to all-time lows, and most would agree below sustainable levels in the longer term. Utility betas have also been impacted, and market risk premium estimates cover a broad spectrum. There is a substantial gap between historic market risk premiums and the higher risk premiums implied in current stock market data. These are problems with the CAPM, and in general, in the current market environment.

As described in the CAPM section, I have attempted to reconcile for these market conditions. I begin with a forecast Canadian risk free rate. The Market Risk Premium I have employed is a combination of both Canadian and U.S. market inputs, including both historic and forward looking estimates. The betas derived from the U.S. and Canadian proxy groups are adjusted for the market mean. I have also provided an alternative analysis that averages the betas adjusted to market and to the utility industry index, but do not find sufficient support for including these results among my primary DCF and CAPM tests.

In determining the appropriate weight to be placed on the DCF and CAPM models, with the CAPM inputs I have described, I believe that equal weight is reasonable. In determining the relative weight placed on the DCF constant growth vs. multi-stage

[159] Terasen Gas Inc., Return on Equity and Capital Structure, Decision, December 16, 2009, at p. 65.
[160] Generic Cost of Capital Proceeding, Decision, May 10, 2013, at p. 80.

models, I have considered the Commission's finding in the 2013 GCOC decision, where it found:

> "The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages."[161]

Utilizing only the multi-stage DCF and the CAPM results for both Canadian and U.S. proxy groups reduces the average to 9.47%. I believe the range produced from the overall average of all models, 10.04%, and that produced by these 4 models, 9.47%, represents an appropriate estimate of FEI's cost of equity. I have also considered my risk premium analysis, and the "alternative CAPM" analysis. These analyses would produce results at the higher (risk premium) and lower (alternative CAPM) end of the overall range. On balance, I have set my ROE recommendation at the low end of the range. I conclude that a cost of equity for FEI of 9.5 percent on 40 percent equity, falls within the range of reasonable results, compensates FEI for its greater risk relative to its Canadian peer group and the Canadian and U.S. proxy group companies, but at the same time does not diverge substantially from the returns of its Canadian peers. I consider 9.5 percent to be the lowest reasonable estimate for FEI's return on equity that meets the standards of a fair return.

[161] Ibid, at p. 70.

I. ASSESSMENT OF U.S. PROXY GROUP BUSINESS RISK RELATIVE TO FEI

In this portion of the Risk Appendix, the risk profiles of the U.S. proxy group are contrasted with FEI. To obtain companies of like-risk, I performed a number of screens to determine a group of essentially pure-play gas utilities with similar risk profiles to FEI. I started with the eleven companies Value Line classifies as Natural Gas Distribution Companies. From that group of 11 companies, I further screened for companies characterized by:

- Credit ratings of at least BBB+ from S&P, or Baa1 from Moody's;
- Pay quarterly cash dividends;
- Earnings growth rates from at least two utility industry analysts;
- At least 70 percent of their operating income from regulated operations in the period from 2012-2014;
- At least 70 percent of their regulated operating income from natural gas distribution service in the period from 2012-2014; and
- Not involved in a merger or other significant transformative transaction during the evaluation period.

The following seven companies met those criteria:

- Atmos Energy Corporation
- New Jersey Resources, Inc.
- Northwest Natural Gas Co.
- Piedmont Natural Gas Co., Inc.
- South Jersey Industries, Inc.
- Southwest Gas Corporation
- WGL Holdings Inc.

In the following pages of this section, I summarize my assessment of each of the U.S. proxy group companies' risk profile and how those proxy companies compare to FEI in terms of business risk. In Section II of this Appendix, I have included a detailed risk template for each of the members of the U.S. and Canadian proxy groups that I have used to develop my assessment.

<u>Atmos Energy Corporation</u> is one of the largest gas distributors in the U.S serving over 3 million customers in eight states. It is rated A- by S&P, noting that they operate in constructive regulatory frameworks, and many of those jurisdictions allow for rate stabilization through weather normalization or rate stabilization mechanisms and accelerated capital recovery programs. Ninety-eight percent of the Company's assets are dedicated to gas distribution operations, with 70 percent of those assets located in Texas. The company's customer base is primarily comprised of residential and commercial customers.

The Company spent $835 million on Capex in 2014, and is estimated to spend approximately $1 billion per year through 2018. Capital trackers are in place in most jurisdictions, providing immediate rate recovery for 45 percent of Capex spend. Most recent returns have been in the high 9 percent to mid- 10 percent range, with equity ratios of upwards of 50 percent in most jurisdictions.

None of Atmos's utilities provide customer choice for gas supply. In Texas, Atmos's largest jurisdiction, heating load only accounts for approximately 22 to 25 percent of the average customer's energy bill and gas is used approximately 40 percent of the time for heating, even though it enjoys a substantial price advantage over electricity, indicating a tremendous opportunity for growth. Gas supply is plentiful and unconstrained, and the majority of jurisdictions operate under monthly purchased gas adjustments, with some of the smaller jurisdictions including gas supply incentive mechanisms and margin sharing.

Atmos's gas utilities operate in regulatory jurisdictions that are all rated average and above average by RRA, with Texas (the largest jurisdiction) assigned an average3 (at the low end of average) rating. Several of the Atmos companies operate under formula rate plans that provide annual rate adjustments (Louisiana, Texas and Mississippi). Some jurisdictions use a forecast test year, but the large Texas utilities use a historic test year adjusted for known and measurable differences. Revenues are stable with approximately

60 – 80 percent of the LDC cost of service covered by the fixed charge, and virtually all jurisdictions are protected from the effects of abnormal weather. The company also is allowed deferral account recovery for bad debt expense in most jurisdictions, energy efficiency covering most operations, and some jurisdictions provide deferral account recovery for employee benefit plans, pension plans and environmental compliance.

Overall, I find the Atmos utilities to be of lower risk to FEI. Though FEI revenues may be more stable due to its forecast test year and full decoupling mechanism, and FEI continues to enjoy timely cost recovery for major capital projects, the challenging competitive environment natural gas faces in BC in addition to the clean air and green energy initiatives pose competitive risks for natural gas that are not present for the Atmos utilities. Further, although both companies enjoy similar gas supply incentives, FEI's performance based rate plan and earnings sharing mechanism may add constraints not present for the Atmos utilities.

New Jersey Resources is a large energy services company, providing gas supply, clean energy services, transportation, distribution and asset management, with annual revenues in excess of $3 billion. New Jersey Resources consist of five primary businesses, the largest of which is New Jersey Natural Gas, its large gas distributor, serving over 500 thousand customers in New Jersey. The other business subsidiaries include NJR Energy Services, which manages a diversified portfolio of natural gas transportation and storage assets and provides physical natural gas services and customized energy solutions to its customers across North America; NJR Clean Energy Ventures, which invests in, owns and operates solar and onshore wind projects with a total capacity of over 125 megawatts; NJR Midstream serves customers from local distributors and producers to electric generators and wholesale marketers through its equity ownership in a natural gas storage facility and a transportation pipeline, both of which are Federal Energy Regulatory Commission; and NJR Home Services, which provides heating, central air conditioning, standby generators, solar and other indoor and outdoor comfort products to residential homes and businesses throughout New Jersey and serves approximately 119,000 service contract customers. Approximately 72 percent of New Jersey Resources assets are dedicated to its gas distribution subsidiary.

New Jersey Resources is rated A by S&P, due in large part to its business risk profile. Credit positives are noted to be its constructive regulatory environment, an economically diverse service area, strong access to gas supply and storage, and lack of competition. However, on the credit negative side, S&P notes that NJR's higher-risk unregulated operations partly offset these strengths. Unregulated operations contribute approximately 10 to 15 percent of the Company's consolidated EBITDA. It is also noted that New Jersey Natural Gas's customer growth is estimated to continue at 1.5 percent per year, due to the trend towards gas conversions from other fuel sources.

The company operates in a high-growth service territory, with easy access to natural gas, comprised primarily of suburban residential customers (84 percent). Its high customer growth is driven by the overall population growth in its service territory, the competitive price advantage of natural gas over alternate fuels, new construction, and natural gas conversions. More than 80 percent of New Jersey households use natural gas for heating and natural gas is installed in 95 percent of new home construction. Though retail competition is available in New Jersey Natural's service territory, only 3 percent of residential customers and 17 percent of non-residential customers have selected a third party gas supplier. New Jersey Natural Gas is not subject to competition by other gas distributors in its service territory, and the potential for bypass risk by large industrial customers is low.

The distribution company's capex spend is roughly $200 million annually, and the anticipated capex spend for gas distribution operations from 2014-2017 is projected to be approximately $800 million overall. The consolidated capex for the total company over the same period is projected to be $1.3 billion. New Jersey Natural Gas has capital trackers for large infrastructure programs, which provide returns on invested capital inclusive of an equity component in the range of 9.75 percent to 10.3 percent.

New Jersey Natural Gas operates under a cost of service regulatory model, based on a partially forecast test year, under the jurisdiction of the New Jersey Board of Public Utilities. The regulatory environment is rated Average/3 by RRA. The regulator provides incentives for natural gas supply procurement (which includes margin sharing), conservation and safety, which provide an opportunity to earn in excess of the allowed return. New Jersey Natural's most recent authorized return on equity and equity ratio were 10.3 percent and 51.2 percent, respectively. The Company has a revenue decoupling mechanism that protects the utility gross margin from the affects of weather and conservation. However, the mechanism is subject to an earnings test. The company also realizes deferral account recovery for its Conservation Incentive Program (decoupling mechanism), New Jersey Clean Energy Program, environmental remediation costs, post employment and other benefits, and costs associated with Superstorm Sandy.

Overall, I consider New Jersey Resources Corp. to be of lower risk than FEI. New Jersey Natural Gas has comparable revenue stability and cost recovery through its decoupling mechanism and series of capital trackers. In addition, the company realizes cost recovery through deferral accounts. Gas supply costs receive comparable recovery since New Jersey receives an annual true up of gas costs. New Jersey's growing customer base and the trend towards new natural gas construction and natural gas conversions, indicates a much less risky competitive environment than FEIs. Further, New Jersey Resources has incentives for key regulatory initiatives. Overall, these factors point to a lower risk profile for New Jersey Natural Gas than FEI, even considering that approximately 30 percent of New Jersey Resources operations are unregulated and higher risk, I have deemed this higher proportion of unregulated operations insufficient to offset the lower risk profile of the regulated distribution company. As such, I consider New Jersey Resources to have less business risk than FEI.

Northwest Natural Gas Company is the largest gas utility in the Pacific Northwest serving approximately 705,000 customers with $3.1 billion of total assets. It is rated A+ by S&P, with primary credit drivers being its strong relationship with the Oregon PUC covering 90 percent of the Company's customer base, resulting in consistently supportive rate design and incentive programs that allow stable cash flows, insulated from gas prices, the effects of weather and/or usage. Unregulated storage facilities comprise approximately 5 percent to 10 percent of the Company's operations, of which the Oregon storage facility contributes approximately 90 percent of the Company's unregulated cash flows. The Oregon storage facility is considered to have very reliable cash flows and very little outside competition. Gas costs are trued up annually in Oregon and more frequently in Washington. Approximately 89 percent of the company's assets are dedicated to regulated gas distribution.

Northwest Natural's service territory is comprised of 59 percent residential and 29 percent commercial and industrial customers. This is a higher concentration of industrial customers than the majority of the proxy companies. A noted concern is that there is a high risk of bypass by industrial customers, but this risk is largely mitigated through competitive transportation tariffs. There is high potential for growth in Northwest Natural's service territory due to the low penetration rate of natural gas heating (approximately 60 percent). The Company enjoys a new customer annual growth rate of 1.4 percent per year as a result of new construction and natural gas conversions. Natural gas enjoys a substantial price advantage to alternate fuels and is easily accessible. There is no direct competition or retail unbundling in Northwest Natural's service territory. The Company has made a large investment in gas reserves to hedge its gas supply risk. This investment earns the same return as that allowed on rate base.

Northwest Natural operates under a cost of service regulatory model in both Oregon and Washington. Both jurisdictions are deemed average by RRA, with Oregon ranked one notch lower than Washington at Average/3, versus Washington's Average/2. Oregon regulation provides for a partially forecast test year and full decoupling, whereas Washington uses a historic test year adjusted for known and measurable differences and has not implemented volumetric decoupling. It's most recent allowed returns are 9.5 percent in Oregon and 10.1 percent in Washington on 50 and 51 percent equity ratios, respectively. The Company enjoys timely recovery of gas costs with no less than an annual true up. In addition, Oregon provides for a gas supply incentive mechanism that provides for margin sharing (subject to an earnings test).

The Company spends approximately $150 million per year on capex and expects to spend $600 million to $700 million in aggregate over the 5 year period from 2014-2018. Significant infrastructure programs receive preapproval by the Oregon regulatory commission and have associated capital trackers. In addition, the Company has regulatory asset treatment of site remediation costs, pension costs and environmental costs that are recovered through deferral account amortization.

Northwestern's risk profile provides earnings opportunities through the return on investments in natural gas reserves that are not available to FEI. In addition, natural gas has greater growth potential in Northwest Natural's service territory than that of FEI, due to the price attractiveness and the trends in new home construction in the Pacific Northwest. FEI has been faced with declining natural gas installations in new construction, particularly in multi-family dwellings due in part to heightened carbon consciousness in British Columbia and more active regulatory initiatives to promote cleaner forms of energy. Though Northwest Natural has a higher concentration of industrial customers and system bypass is a valid risk, this risk has historically been mitigated by competitive transportation tariffs. Northwest Natural's revenues are stable due to the decoupling provision in Oregon, and even though Northwest Natural has unregulated storage operations, the associated revenues are deemed to be stable and do not add substantially to the risk profile of the Company. Overall, Northwest Natural has greater earnings potential than does FEI with no notable additions of risk. As such, they are considered to be less risky than FEI in my analysis.

Piedmont Natural Gas Co., Inc. distributes natural gas to over 1 million customers in North Carolina, South Carolina and Tennessee, with $3.6 billion of total assets, of which 97 percent is dedicated to regulated natural gas operations. It is rated A by S&P, with primary credit drivers being its generally constructive regulatory environments, the low operating risk of its natural gas transmission and distribution business, and attractive service territories that continue to show strong customer growth. The company does have an unregulated wholesale marketing subsidiary that is viewed as higher risk, but its activities are expected to decline in coming years. Piedmont's business risk profile also benefits from growth capital spending and its ability to recover infrastructure investments through riders in North Carolina and Tennessee.

Piedmont enjoys strong growth in its service territories, averaging 1.6 percent overall customer growth for 2014 and the same is projected for 2015. The increase is due primarily to new home construction (72 percent) and natural gas conversions (17 percent), the remaining 11 percent is attributable to the addition of new commercial and industrial customers. Natural gas has a relatively low penetration rate in Piedmont's service territories (between 25 and 33 percent) and it enjoys a significant price advantage over its closest competitor, electricity. Piedmont's customer mix is primarily residential and commercial at 90 percent and 9 percent of customers, respectively. However, industrial sales comprise roughly 14 percent of the Company's revenues and there is one large customer that contributes 6 percent of total operating revenues. Piedmont does have a higher risk of system bypass by industrial customers and directly competes with interstate pipelines to serve generation customers. There is no retail customer choice in any of Piedmont's regulatory jurisdictions and Piedmont is the sole supplier of natural gas for the residential and commercial customer classes.

The Company enjoys easy access to low cost natural gas in its service territories and has sufficient pipeline capacity and storage capacity to minimize price volatility. Fuel clauses provide annual true ups, subject to a prudence review. Some jurisdictions have fuel cost incentive mechanisms and all jurisdictions provide for margin sharing for gas supply costs.

Piedmont is regulated under a cost of service framework in South Carolina and formula rate plans that adjust annually in Tennessee and North Carolina. The Tennessee jurisdiction utilizes a forecast test year, whereby the other jurisdictions use a historical test year adjusted for known and measurable changes. Piedmont has an earnings sharing mechanism in South Carolina that provides for a rate adjustment if earnings are outside of a 50 basis point deadband. Recent authorized returns range from 10 percent in North Carolina to 10.2 percent in South Carolina and Tennessee, with equity ratios ranging from 50.7 percent (North Carolina) to 55 percent (South Carolina).

The company is investing heavily in regulated infrastructure with annual capex ramping upwards from $515 million in 2014 to $630 million in 2017. It reports that 72 percent of the gas utility margin is fixed by a combination of decoupling in North Carolina, Integrity Management Riders in North Carolina and Tennessee, facilities charges, and fixed rate contracts; 16 percent is partially fixed by revenue stabilization in South Carolina and weather normalization in South Carolina and Tennessee; leaving only 12 percent of the gas utility margin subject to volumetric risk. Further, construction work in progress receives an AFUDC rate that includes an equity component and South Carolina and Tennessee allow for a return on CWIP. The company also has deferral accounts and riders that collect for uncollectible gas cost recovery, environmental costs, storm costs, and lost margin due to system bypass by large industrial customers.

Overall, I consider Piedmont to be less risky than FEI. Piedmont has good revenue stability but does not have full decoupling as is the case with FEI. Piedmont has cost recovery through its infrastructure riders and returns on CWIP. This is given significant weight in my assessment, given Piedmont's substantial and growing infrastructure and reliability investments. Gas supply costs receive comparable recovery to that of FEI through an annual true up of gas costs. Piedmont's growing customer base and the trend towards new natural gas construction and natural gas conversions indicates a less risky competitive environment than FEI's, where natural gas faces political and legislative initiatives to decrease the use of carbon intensive fuels in the Province. Additionally, natural gas in BC does not enjoy the competitive price advantage found in the states, particularly in Piedmont's service territory. Gas supply incentives and margin sharing provide similar opportunities to increase earnings beyond the allowed return between the two companies. The higher risk unregulated operations are insignificant and are given little weight in my assessment. Overall, these factors point to a lower risk profile for Piedmont than FEI.

South Jersey Industries, Inc. is an energy services holding company comprised of South Jersey Gas, a New Jersey gas distribution company serving 365,000 customers; and South Jersey Energy Solutions, comprising South Jersey's non-regulated gas services operations. The gas distribution portion of South Jersey makes up approximately 68 percent of $1.8 billion in consolidated assets. South Jersey is rated BBB+ by S&P with major credit drivers being the low risk profile of South Jersey's regulated gas distribution operations, comprising approximately 85 percent of operating income. S&P also notes South Jersey's attractive service territory with above average growth rates. The unregulated portion of South Jersey's operations are higher risk.

South Jersey's service territory is comprised of 93 percent residential customers and approximately 7 percent commercial and industrial. It operates in a service territory where new customer growth is approximately 1.4 percent and is slated to be 2 percent going forward, primarily due to gas conversions (currently making up 69 percent of new customer growth). New Jersey regulation provides for customer choice where, approximately 8% of residential customers and 15% of non-residential customers participate.

Natural gas enjoys approximately 70 to 80 percent market share for heating compared to other energy alternatives. The Company projects 10 percent penetration for CNG. Gas supply is abundant in South Jersey's service territory and enjoys a substantial competitive price advantage. Gas costs are recovered through an annual true up (industrial customers are trued up monthly) and the Company has a gas supply incentive mechanism that provides for margin sharing of transportation and off-system sales margins.

South Jersey operates under a cost of service regulatory model, based on a partially forecast test year, with most recent returns granted at 9.75 percent on a 51.9 percent equity share. The Company has a full decoupling mechanism, though it is subject to an earnings test; and enjoys cost recovery through a program of capital trackers and riders for infrastructure, storm hardening, and energy efficiency. For other types of construction in progress, the Company earns an AFUDC that includes an equity and debt component. The Company spends approximately $200 million annually on Capex. The company recovers the costs associated with pensions and post-retirement benefits, interest rates, social benefits, remediation, clean energy, pipeline integrity and storm costs through deferral and variance accounts.

Overall, I consider South Jersey Gas to be of comparable risk to FEI. South Jersey has comparable revenue stability and cost recovery through its decoupling mechanism and series of capital trackers. In addition, the company realizes cost recovery through deferral accounts. Gas supply costs receive comparable recovery since South Jersey receives an annual true up of gas costs. South Jersey's growing customer base and the trend towards new natural gas construction and natural gas conversions, indicates a much less risky competitive environment than FEIs. Overall, these factors point to a lower risk profile for South Jersey Gas than FEI, however, because approximately 15 percent of South Jersey's operating income comes from unregulated operations, I consider these differences to be offsetting and therefore the risk profile of South Jersey is comparable to FEI in terms of business risk.

Southwest Gas Corporation is a gas distribution company serving approximately 1.9 million customers in Arizona, Nevada and California. The Company is rated A- by S&P, primarily for its low risk regulated operations and geographic and regulatory diversification. The company enjoys supportive regulation by means of riders for purchased gas, accelerated pipe replacement and infrastructure programs. Approximately 17 percent of the company's operations are dedicated to unregulated pipe replacement services. The Company dedicates 94 percent of its $4.4 billion in consolidated assets to its regulated distribution activities.

The Company expects to realize 5.2 percent compound growth in utility plant in all jurisdictions from 2012-2014. The Company plans to spend $1.3 billion between 2015 and 2017 on capital, of which 5 percent is expected to be collected through riders.

Forecasts show that an ample and diverse natural gas supply is available to Southwest's customers at a highly competitive price when compared with competing forms of energy. Natural gas has a relatively low penetration rate in Southwest's jurisdictions ranging from 30 to 60 percent, with the closest competitor being electricity. This provides a growth opportunity for new construction and natural gas conversions. The Company realized 1.4 percent customer growth for 2014 and projects 1.5 percent customer growth for 2015. However, this growth is primarily attributable to the return to service of previously vacant homes in a largely depressed service territory, which are typically above the national average for unemployment. Southwest is exposed to significant bypass risk in its service territory as it competes with interstate pipelines for serving large end-users. It mitigates this risk by offering specially negotiated, discounted rates with large industrial users.

Southwest operates under cost of service regulatory models in jurisdictions rated average by RRA. Both Arizona and Nevada use historic test years adjusted for known and measurable differences, whereby California uses a forecast test year. There are a small number of customers that have adopted customer choice in California, but Arizona and Nevada have not unbundled retail gas sales from distribution. California imposes compliance with a handful of clean air regulations and initiatives, but the associated costs are allowed regulatory recovery. Most recent returns have ranged from 9.3 percent to 10.10 percent on equity ratios ranging from 42.7 percent to 59.1 percent. The Company has a decoupled rate design in all jurisdictions and recovers gas costs through monthly purchased gas adjustments in Arizona and California, and through quarterly adjustments in Nevada. The Company also has deferral recovery for GIR Surcharges, annual attrition increases, and greenhouse gas trading balancing accounts.

Overall, I find the Southwest Gas' risk profile to be comparable to FEI. Both companies share comparable revenue stabilization through full decoupling mechanisms and both companies enjoy timely cost recovery for major capital projects. FEI's performance based rate plan and earnings sharing mechanism may add constraints not present for Southwest Gas. Further, the clean air and green energy initiatives in BC pose competitive risks for natural gas that are not present for Southwest Gas, except in California where the Company recovers any costs associated with such initiatives. Both companies operate in somewhat challenging competitive environments. Southwest Gas because of its challenging regulatory jurisdiction where unemployment is high and gas conversions and new construction is relatively low; FEI because of its close competition with electricity, and the climate initiatives in BC which pose a long-term threat to natural gas. Though Southwest has an unregulated gas infrastructure operation, it is relatively low risk, though higher risk than its regulated gas operations. I consider these differences to be largely offsetting, and find the advantages FEI has being 100 percent regulated are offset by the limits of its performance based ratemaking plan.

WGL Holdings Inc. is a large diverse energy company with regulated and unregulated natural gas-related operations. Its largest subsidiary is Washington Gas Light (WGL), a regulated gas distribution company serving approximately 1.1 million customers in Washington D.C., Maryland and Virginia. The Company is rated A+ by S&P, primarily for its low-risk regulated operations, its affluent and supportive service territory, supportive regulatory mechanisms, moderate regulatory and market diversification and low operating risk. S&P notes a number of regulatory mechanisms that stabilize its cash flows, e.g. decoupling mechanisms, purchased gas adjustment mechanism, weather normalization clauses and bad debt recovery. Allowed ROEs have been near 10 percent in all jurisdictions. Higher-risk unregulated operations make up roughly 15 percent of operating income, though several of the unregulated units have a very similar risk profile to the regulated utility, due to the long-term income stream from energy sales contracts (e.g. solar projects). Approximately 85 percent of the consolidated company's $4.1 billion of assets are dedicated to regulated operations.

Customer choice programs for natural gas customers are available to all of Washington Gas' regulated utility customers in the District of Columbia, Maryland and Virginia. Approximately 16 percent of customers purchased their natural gas commodity from unregulated third party marketers. WGL's service territory enjoys ready access to natural gas and it is used 25 to 35 percent of the time for home heating, representing a growth opportunity for WGL. Washington Gas generally maintains a price advantage over competitive electricity supply in its service area for traditional residential uses of energy such as heating, water heating and cooking and continues to attract the majority of new residential construction market in its service territory. Consumers' demonstrate a continuing preference for natural gas and utility meter growth is 1.6 percent. The Company is pursuing opportunities to increase penetration in the multi-family market. Natural gas currently serves over 90 percent of new single family homes. Further, new tariffs with low customer contributions are driving a higher conversion rate. The nature of Washington Gas' customer base and the distance of most customers from interstate pipelines mitigate the threat of bypass of its facilities by other potential delivery service providers.

All jurisdictions provide for recovery of gas costs through quarterly adjustment mechanisms except for Maryland which provides for an annual adjustment. Further adjustment charges for uncollectible gas costs and carrying costs on storage inventory may be run through the PGA in each state. Hedging costs are also run through D.C.'s PGA. There is margin sharing of gas supply and asset management costs in Maryland and Virginia.

Capital spending is anticipated to be $1.8 billion for the regulated utility over the next 5 years; and spending for the entire company over the same period will be $2.8 billion. All jurisdictions receive regulatory approval for significant infrastructure replacement programs and have associated capital trackers so that there is no lag in recovery for these programs. For items not recovered through trackers, the Company provides for AFUDC for construction in progress that is prescribed by formula to derive the before tax return on capital charge. The utility also recovers costs associated with changes in tax treatment as well as pension and benefits in Washington D.C. through regulatory deferral accounts. It also receives deferral account treatment for energy efficiency expenditures and bad debt expenses in the majority of states in which it operates.

The company's regulatory jurisdictions are rated Above Average/2 (Virginia), Average/3 (DC), and Below Average/2 (Maryland), with Virginia and D.C. comprising roughly 60 percent of the company's customers. All of the WGL jurisdictions operate under a cost of service regulatory model, with earnings shared with customers on a 60/40 basis. Virginia provides earning incentives for meeting demand reduction targets. All jurisdictions use a historical test year, with known and measurable differences, though D.C. does consider some forecasted items in its test year determination. Most recent allowed returns ranged from 9.25 percent in D.C. to 9.75 percent in Virginia on equity portions ranging from 53 percent in Maryland and 63 percent in Virginia. The majority of customers are subject to full decoupling, except in D.C. where there is only weather normalization.

Overall, I consider WGL to be less risky than FEI. WGL has revenue stability as is the case with FEI. WGL also enjoys cost recovery through its infrastructure riders and returns on CWIP, as well as its gas supply costs which are allowed returns on storage inventory and provide similar upside earnings potential through margin sharing arrangements for gas supply as FEI enjoys with its Gas Supply Mitigation Incentive Plan. WGL's growing new customer base and the trend towards new natural gas construction and natural gas conversions indicates a less risky competitive environment than FEIs, where natural gas faces political and legislative initiatives to decrease the use of carbon intensive fuels in the Province. Additionally, natural gas in BC does not enjoy the magnitude of the competitive price advantage found in the states. Gas supply incentives and margin sharing provide opportunities to increase earnings beyond the allowed return for both companies. The higher-risk unregulated operations of WGL are similar to the risk profile of a regulated utility since much of the earnings stream is contracted and long-term. As a result, the unregulated operations have little bearing on my overall assessment. Overall, these factors point to a lower risk profile for WGL than FEI.

II. DETAILED RISK TEMPLATES FOR PROXY GROUP MEMBERS

Fortis Inc. (TSX: FTS)

<table>
<tr><th colspan="2">SNL Financial Company Overview[1]</th></tr>
<tr><td colspan="2">Fortis is a leader in the North American electric and gas utility business, with total assets of more than $26 billion and fiscal 2014 revenue of $5.4 billion. Its regulated utilities account for approximately 93% of total assets and serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (A-/Stable/--)[2]</th></tr>
<tr><td>Business Risk – Excellent

In our view, Fortis' excellent business risk profile continues to benefit from its stable, low-risk, and regulated utility portfolio. Regulation typically involves a cost-of-service methodology that provides an allowed regulated rate of return. We believe the utilities have relatively low levels of commodity and volume risk exposure, further reducing cash-flow volatility. Fortis' regulated companies have monopolies as service providers in their service areas. They are exposed to limited bypass risk and are relatively insulated from typical market forces, which we view as a credit strength for Fortis. In our view, another key credit strength for the company is the regulatory, geographic, and market diversification of its subsidiaries and their cash flows. There continues to be some concentration in British Columbia, where about 50% of the rate base is located. In our view, the addition of TEP from Fortis' acquisition of UNS will reduce this concentration and provide further diversification to cash flows. This diversification effect partially offsets the impact of TEP's "strong" business risk profile, which is weaker than Fortis's excellent profile, reflecting our view that TEP is exposed to generation and environmental risks, as well as concentration risk arising from operating in only one market. We believe that although adding TEP would marginally weaken Fortis' business risk profile, it is likely to remain excellent. We also believe that the proportion of somewhat higher-risk cash flows from UNS would not be significant enough to cause any weakening in Fortis' business risk profile. The unregulated businesses make a relatively small consolidated contribution to the group, at approximately 15%. The size and quality of these cash flows will improve with the Waneta project's completion. We believe this project has limited hydrology and price risk, no dispatch risk, and strong counterparties in British Columbia Hydro & Power Authority and Fortis BC.</td>
<td>Financial Risk – Significant

We expect Fortis' cash flows from the regulated utilities to remain very stable, a factor we believe is a key credit strength that offsets the company's high leverage. Regulated utility cash flow is primarily composed of a return of capital (depreciation) and a return on capital, both of which continue to experience limited volatility. Consolidated leverage is a function of the regulatory capital structure of the underlying utilities that generally follows levels regulation allows. We have assumed rate-base growth leads to corresponding growth in cash flow. We believe that the UNS addition would modestly improve Fortis' financial metrics. We forecast TEP, the company's largest provider of cash flow, to have an AFFO-to-total debt ratio of greater than 20%, compared with Fortis' 10%-11%. We forecast AFFO-to-total debt ratio for Fortis in the 12%-13% range in 2015 and 2016, improving to more than 13% in 2017. Based on our forecast, we have assessed the company's financial risk as significant.</td></tr>
</table>

Operating Characteristics	

Operations/State/Customers (000's)[3]	1,194 million gas customers and 1,947 million electric customers; approximately 33% of operations is located in BC
	• UNS Energy – AZ – 150 (Gas), 508 (Electric)
	  o In August 2014, Fortis acquired UNS Energy for approximately $4.5 billion, a vertically integrated electric generation company in AZ, serving approximately 656 thousand electric customers.
	  o At 1.1.2015, TEP owned 2,746 MW[4] of generating capacity, ~50% is coal fired[5]
	  o TEP has sufficient owned and contracted generation capacity to cover its energy needs.[6]
	• Fortis BC – BC – 967 (Gas), 166 (Electric)[7]
	  o Owns 4 hydro-electric generating plants with aggregate capacity of 225MW, providing ~ 45% of energy needs (~30% of peak capacity).
	  o Balance of electric needs met w/ long and short-term PPAs.
	• Central Hudson – NY – 77 (Gas), 300 (Electric)[8]
	  o Electric utility is T&D only.
	• Fortis Alberta – AB – 530 (Electric)[9]
	  o Electric utility is D only
	• Eastern Canada – NF, Maritimes, ONT – 402 (Electric)[10]
	  o Newfoundland Power purchases ~93% of energy requirements from NF Hydro.
	  o Balance of NP electric needs are met w/ small hydro, diesel and gas generating facilities.
	  o Maritime Electric purchases 76% of energy needs from NB Power, balance met w/ purchases of wind owned by PEI Energy and from company-owned on island generation
	  o FortisOntario purchases 100% of its energy requirements.
	• Caribbean Electric – 41 (Electric)

Total Assets (2013 $CAD billions)	$26[11] • In Sept. 2014, Fortis announced that it is reviewing strategic options for its hotel and commercial real estate business (Fortis Properties, which currently comprises 3% of

	total assets).[12]
% of Assets in Regulated Distribution Operations (2013)	93% (26% in gas distribution operations and 67% in electric distribution operations)[13]
Customer Mix (2014 Revenues)[14]	• UNS Energy – AZ o Residential – 36.2% o Commercial – 22.5% o Industrial – 16.9% o Other 24.4% • Central Hudson – NY o Residential – 60.9% o Commercial – 28.0% o Industrial – 4.1% o Other 6.2% o Sales for Resale 0.8% • FortisBC Energy Companies o Residential – 56.2% o Commercial – 30.2% o Industrial – 2.7% o Transportation – 6.8% o Other 4.1% • FortisAlberta o Residential – 30.5% o Large Commercial and Industrial – 21.5% o Farms – 11.8% o Small Commercial – 10.8% o Small Oil Field – 8.1% o Other - 17.3% • FortisBC Electric o Residential – 48.4% o Commercial – 24.7% o Wholesale – 13.0% o Industrial – 9.0% o Other – 4.9% • Eastern Canadian Electric Utilities o Residential – 56.1% o Commercial – 41.1% o Other – 2.8% • Regulated Electric Utilities - Caribbean o Residential – 44.0% o Commercial and Industrial – 54.9% o Other – 1.1%
CAPEX Spend[15]	• Gross Capex for 2014 was $1.7 billion, and was $4 billion from 2012-2014 • Over next 5 years, investment in energy infrastructure is expected to increase rate base by ~ 36%, translating to 6.5% CAGR in rate base. • Breakdown of capital spending from 2015-2019 is as follows: o 38% Canadian electric utilities

	(driven by Fortis Alberta) o 35% U.S. combo gas/electric utilities (driven by UNS at 20%) o 20% Canadian gas utilities o 5% Caribbean utilities o 2% non-regulated operations • Gross 2015 Capex to be $2.2 billion • Significant Capex: o Waneta Expansion CAD$76 million in 2015 o Tilbury LNG up to CAD$400 million, plus further $450 million expansion (Phase 2) o Purchase of UNS ownership interest in Springerville generating station US$46 million o Expected purchase of UNS expiring lease interests in Springerville coal handling facilities US$73 million o Pinal Transmission Project – UNS transmission line to increase UNS import capacity US$85 million o CAD$600 million pipeline expansion Woodfibre LNG site in BC. • Forecast 2015 Mid-year rate base total of CAD$15.2 billion: o UNS Energy - CAD$3.8 billion o Central Hudson – CAD$1.3 billion o FortisBC Energy companies – CAD$3.7 billion o FortisAlberta – CAD$2.7 billion o FortisBC Electric – CAD$1.3 billion o Eastern Canadian Electric Utilities – CAD$1.6 billion o Regulated Electric Utilities – Caribbean – CAD$0.8 billion
Service Territory	• Large proportion of the businesses of Fortis serve economies of western Canada, where economic growth has generally been higher than the rest of the country. Western Canada assets comprise approximately 67% of total regulated assets.[16] • Fortis Alberta is the largest growing utility with rate base of $2.3 billion, serving some of the fastest growing areas of Canada related to oil sands and shale oil developments and associated residential and commercial developments in communities surrounding cities of Calgary and Edmonton.[17]

	• On December 31, 2014, FEI amalgamated with FEVI, FEWI. Largest distributor of natural gas in BC serving more than 125 communities. FEI provides T&D services and provides natural gas.[18]
	• FEI owns and operates approximately 47,500 kilometers of gas pipelines and met a peak day demand of 1,324 TJ in 2014.[19]
	• FortisAlberta serves customers in its service territories through franchise agreements with the respective municipalities. Municipalities have the right to purchase FortisAlberta's assets within its municipal boundaries at an agreed upon negotiated price, failing which it is determined by the AUC. Further if municipality extends its boundaries, it may purchase FortisAlberta's assets in the newly annexed portion of the municipality and must pay FortisAlberta replacement cost less depreciation. Fortis Alberta holds franchise agreements with 140 municipalities – new Alberta franchise agreements contain 10-yr. initial terms and may be renewed at 5-year increments. Fortis has converted 95 of existing franchises to new agreements and to convert 90% of the remaining municipalities by the end of 2015.[20]
	• The FortisBC companies provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of the FortisBC Energy companies and FortisBC Electric is not clear.[21]
	• FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta. In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval.
	• Population Growth CAGR
	  o NY – 0.4%[22]
	  o AZ – 1.1%[23]
	  o BC – 1.1%[24]
	  o ALB – 1.6%[25]
	• Per Capita Income CAGR 2009-2013
	  o NY – 3.2%[26]

	o AZ – 2.1%[27] o BC – 3.9%[28] o ALB – 4.3%[29] • Employment growth o BC – 0.9%[30] o ALB – 1.4%[31]
Residential Retail Unbundling[32]	• Retail customers may elect to procure electricity from 3rd party suppliers, ~ 16% purchase from ESCO - NY • No retail unbundling – AZ • FEI offers customer choice program to eligible commercial and residential customers. In 2014 ~7% of commercial customers and ~5% of residential customers participated in the program.[33]
Climate[34]	• AZ – Climate is warmer than national average - space heating accounts for approx. 15% and water heating accounts for approx. 17% of energy bill • NY - Climate is cooler than national average - space heating accounts for approx. 52% and water heating accounts for approx. 17% of energy bill • BC – Close to 90% of FEI's delivery revenue, or gross margin, is derived from the residential and commercial sectors, of which over 80% is from space and water heating applications.[35]
Supply Availability and Deliverability	• Majority of natural gas production in northern BC has served the provincial and Pacific Northwest markets via the Westcoast Spectra System, the remainder is sourced in Alberta and transported on TransCanada.[36] • FortisBC Energy companies purchase gas supply to service customers and contracts for ~ 138 PJ of baseload and seasonal supply.[37] • The FortisBC Energy companies hold approximately 35.5 PJs of total storage capacity consisting of two peak shaving LNG facilities and off-system capacity contracted with third parties.[38]
Competition with other Fuel Sources	• BC - Combination of plentiful gas supply, improved economics and more positive government policy is generating new interest for large industrial customers and niche LNG producers.[39] • BC - Natural gas is positioned to enter new markets such as transportation sector (CNG & LNG).[40] • BC – trend in housing starts from single family dwellings to multi-family dwellings, for

	which natural gas has a lower penetration rate.[41] • BC – Electric prices in BC are based on heritage costs and not market, this has eroded the cost disadvantage of electricity over natural gas, however, recent lower natural gas prices due to the Shale boom have maintained the natural gas price advantage in BC. • BC has captured ~51% of residential market share, though that amount has been declining over time[42]
Competitive Price Advantage[43]	• Natural gas enjoys significant price advantage in the U.S. across all customer classes (between 1/3 and ¼ of electric price)
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[44]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. AZ - Average/3 /DBRS 41 NY - Average/2 /DBRS 34 BC – DBRS 40 ALB – DBRS 30.5 ONT – 33 NF – 37 PEI – 37
Regulatory and Legislated Initiatives	• TEP and UNS Electric are subject to government mandated renewable energy requirements.[45] • TEP is subject to new EPA standards which target coal emissions, and is seeking relief from compliance.[46] • Government of BC exempted FEI's Tilbury LNG facility from normal course regulatory review and laid out specific requirements for the regulator, including a second phase for the Tilbury expansion that would include liquefaction and could increase total cost for both phases to $850 million.[47] • BC is subject to Carbon Tax Act, Clean Energy Act, Greenhouse Gas Reduction (Cap and Trade) Act, and Greenhouse Gas Reduction Targets Act; all of which place pressure on natural gas consumption. o Carbon Tax Act improves competitive position of natural gas relative to other fossil fuels.[48] • BC is participant in Western Climate Initiative which expects to implement a cap

	and trade program.[49]
Regulatory Model[50]	• Cost of Service regulatory model – UNS, TEP, CH, NP, ME, Turks and Caicos • PBR – FEI (2014-2019), FBC (2014-2019), FortisAlberta (2013-2017), FortisOntario (Incentive Rate Setting Mechanism), Caribbean Electric Utilities (Rate cap adjustment mechanism) • Incentive Mechanisms – FBC and FEI (PBR Plan includes incentives for improving O&M and Capex efficiencies). • Earnings Sharing – CH, FEI, FBC
Test Year[51]	• Historical with known and measurable changes – TEP, UNS, Caribbean Electric, Turks and Caicos • Forecast test year – CH, FEI, FBC, FortisAlberta, NP, ME, FortisOntario
Interim Rates[52]	Allowed under some circumstances – AZ (UNS, TEP), NY Routinely allowed – FEI, FBC Not allowed –
Typical Rate Case Lag[53]	AZ – 11 - 17 mos. NY – 11 mos. BC - 9 mos.
Most Recent Authorized ROE[54]	TEP – 10.0% UNS Electric – 9.5% UNS Gas – 9.5% Central Hudson – 10.0% (ROE will be 9.0% effective July 1, 2015) FEI – 8.75% FEVI – 9.25% FEWI – 9.5% FBC – 9.15% FortisAlberta – 8.75% Newfoundland Power – 8.8% + or – 50 bps Maritime Electric – 9.75% FortisOntario – 8.93% - 9.85% Caribbean Utilities – WACC – 7.0% - 9.0% Turks and Caicos – WACC – 15.0% - 17.0%
Most Recent Authorized Equity Ratio[55]	TEP – 43.5% UNS Electric – 52.6% UNS Gas – 50.8% Central Hudson – 48.0% FEI – 38.5% FEVI – 41.5% FEWI – 41.5% FBC – 40.0% FortisAlberta – 41.0% Newfoundland Power – 45.0% Maritime Electric – 40.0% FortisOntario – 40.0%

	Caribbean Utilities – N/A Turks and Caicos – N/A
Gas Supply Risk Mitigation and Incentives	Purchased Gas Adjustment Clauses: • NY – Monthly power costs adjustments for customers who have not selected an alternate provider [56] • AZ – TEP, UNS – use a forward looking fuel adjustment clause.[57] • FEI - Difference between forecast cost of natural gas purchases, and the actual cost of natural gas purchases is captured in a variance account and is recovered from, or refunded to, customers in future rates.[58] • FEI engages in off-system sales activities that allow for the recovery or mitigation of costs of any unutilized supply and/or pipeline and storage capacity that is available once customers' daily load requirements are met.[59] • FEI has GSMIP revenue sharing model, which provides for an incentive payment while remaining savings are credited to customers through rates. Incentive payment is roughly $1 million per year. This program was approved in 2011 and extended in 2013 to 2016.[60] • In July 2011 the BCUC directed FEI to suspend the majority of hedging activities and all hedges expired in 2014.[61]

Volume /Demand Risk Mitigation	• Revenue Stabilization[62]
	  o Full decoupling mechanism – NY, BC (RSAM)
	  o Partial decoupling - UNS Gas, UNS Electric and TEP – has incentive based conservation decoupling mechanism call Lost Fixed Cost Recovery (LFCR) plan that allows greater amounts of recovery as it meets energy efficiency goals, capped at 1% of revenues with differences deferred to future periods with interest.

Capital Cost Recovery Risk Mitigation[63]	• CWIP is allowed under certain circumstances - NY • AFUDC with equity return – UNS, CH, FortisBC Energy, FortisBC Electric, FortisAlberta, NP, ME CU • Established pre-approved capital investment programs o FEI – LNG Expansion • Capital Trackers – FortisAlberta capital tracker - pending

Other Significant Deferral and Variance Accounts[64]	• Central Hudson – NY – recovery is subject to earnings test o Incremental pension expense o Post employment benefits o Interest on variable rate debt o Incremental litigation costs re.: asbestos o Research and development costs o Property taxes o Changes in accounting standards o Changes in government regulations that impact income by > 2% o Stray voltage program expense o Customer and community benefits obligation • UNS o Renewable energy surcharge o DSM adjustment mechanism o Environmental compliance adjustment mechanism. o Deferred lease costs (Springerville) o Transmission cost recovery Mechanism o Mine reclamation and retiree health care costs o Property tax deferral o Customer and community benefits obligation • FortisAlberta o Deferred operating overhead costs o AESO charges deferral • FortisBC Energy and FortisBC Electric o Income taxes recoverable on OPEB plans o Deferred energy management costs o Deferred lease costs (FBC) o Deferred net losses on disposal of utility capital assets and intangible assets o Natural gas for transportation incentives deferral (FEI) o Customer care enhancement project cost deferral o Customer and community benefits obligation

Canadian Utilities (TSX: CU)

SNL Financial Company Overview[65]	
With more than 6,800 employees and assets of approximately $17 billion, Canadian Utilities Limited is an ATCO company, a diversified global corporation delivering service excellence and innovative business solutions through leading companies engaged Utilities (pipelines, natural gas and electricity transmission and distribution) and Energy (power generation and sales, industrial water infrastructure, natural gas gathering, processing, storage and liquids extraction).	
S&P Ratings Summary (A/Stable/A-1)[66]	
Business Risk – Excellent	**Financial Risk – Significant**
We believe the Alberta-based regulated utilities that CU Ltd. holds will continue to generate stable cash flow, which we expect to increase to more than 60% of consolidated cash flow in the next few years, anchoring the business risk profile. CU is predominantly exposed to a single regulator, the Alberta Utilities Commission (AUC), so it does not benefit from meaningful regulatory diversity. However, we expect the AUC's regulatory framework to continue to support cost recovery, and a return on and of capital and stable cash flow. In our view, all of CU's regulated utilities benefit from a reasonably independent, transparent, and predictable approach to regulation. The AUC operates within its legislative framework and sets rates for utilities in Alberta without political interference. Rate decisions are generally based on lengthy, but public, cost-of-service hearings; decisions are published and the rationale explained. We don't expect incentive-based ratemaking for the distribution utilities to increase the risk of lower returns or capital disallowance. To date, material decisions from a credit perspective have been consistent and largely predictable (in particular with respect to deemed capital structure and returns allowed). Rate decisions often take time (up to a year), but we don't expect this to have a rating impact and timeliness could improve with the recent introduction of performance-based ratemaking for distribution utilities. We expect ATCO Power, which operates in an environment with "moderately high" industry risk will contribute approximately 15%-20% of cash flows with some variability. ATCO Power's level of fleet contractedness of about 60%, strong counterparties, and declining project-financed nonrecourse debt in its independent power projects offset the higher industry risk. The fleet is concentrated in Alberta but has what we view as a good operational track record. ATCO Structures and Logistics' cash flow are typically project-focused, so the company has near-term cash flow visibility. It has more variable long-term cash flow that is influenced by commodity pricing and the macroeconomic	We have assessed ATCO's financial risk profile as "significant" using our medial volatility table. The majority of cash flow comes from regulated activities and a majority of operating cash flow from those regulated activities benefits from a better-than-adequate regulatory advantage. We expect weighted average AFFO-to-debt at about 17%, with large investments in the regulated rate base placing downward pressure on consolidated credit metrics but increasing the proportion of regulated assets. Absent any major acquisitions, Standard & Poor's expects ATCO's capital structure to remain stable in the medium term, because the company will partially fund growth in the regulated business with debt. We base this on ATCO's track record of managing the utility balance sheets in line with the regulator-established deemed capital structure to set rates, amortizing project finance debt at ATCO Power's contracted power assets that approximately matches the duration of contract terms, no or low levels of debt in other riskier parts of the organizational structure, and no debt at the parent level.

environment, which drive the need for their products and services. Cash flow from this segment accounts for 15%-20% of consolidated cash flow. The "strong" management and governance score for the group has no direct impact on the ratings but reflects our assessment of management's consistently conservative approach to risk mitigation, with policies and a track record of keeping cash on hand; a stable, long-term strategic horizon compared with that of peers; demonstrated operational effectiveness; and no history of earnings or cash flow surprises.	
Operating Characteristics	
Operations/State/Customers (000's)[67]	• ATCO Electric - 252 o ATCO Electric, NUY, NWT and AEY own and operate 27 diesel, natural gas turbine and hydro-generating plants, with an aggregate nameplate capacity of 62 MW in Alberta, the Yukon and Northwest Territories. The maximum peak load demand for these plants during 2014 was 30 MW. • ATCO Gas – 1,100 • ATCO Gas Australia – 700
Total Assets (2014 $CAD billions)[68]	$16.7 billion
% of Assets in Regulated Distribution Operations (2014)[69]	Utility group makes up 80% of total assets (which includes gas and electric transmission operations in addition to distribution operations), inclusion of ATCO Australia brings total to 87% (which includes power operations in addition to gas distribution operations)

Customer Mix (2014)[70]	• ATCO Electric, NUY, NWT and AEY (Customers)
	    o Customers
	        ▪ Residential – 70%
	        ▪ Commercial – 13%
	        ▪ Industrial – 5%
	        ▪ Rural, REAs, Other – 12%
	    o Delivered GWh
	        ▪ Residential – 12%
	        ▪ Commercial – 21%
	        ▪ Industrial – 62%
	        ▪ Rural, REAs, Other – 5%
	• ATCO Gas
	    o Customers
	        ▪ Residential – 92%
	        ▪ Commercial – 8%
	        ▪ Industrial – --%

	- Other – --%
	- Delivered PJ
	  - Residential – 48%
	  - Commercial – 47%
	  - Industrial – 5%
	  - Rural, REAs, Other – --%
	- ATCO Gas Australia
	  - Customers
	    - Residential – 98%
	    - Commercial – 2%
	    - Industrial – --%
	    - Other – --%
	  - Delivered PJ
	    - Residential – 38%
	    - Commercial – 11%
	    - Industrial – 51%

CAPEX Spend[71]	- Gross Capex for 2014 was $2.3 billion, and the utilities portion was 2.1 billion or 91%, driven primarily by electric transmission operations.
	- In 2015 – 2017 CU plans Capex of $5.8 billion, $4.8 billion for Canadian utility operations
	  - $3.1 billion for electric transmission operations.
	  - $1.7 billion to be shared between gas distribution and pipeline operations.
	- Capex for Canadian Gas Distribution operations runs ~$300 million annually

Service Territory	- ATCO Gas distributes natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. This subsidiary serves more than 1.1 million customers in nearly 300 Alberta communities. These communities have a combined population of approximately 2,640,000. At December 31, 2014, approximately 80% of ATCO Gas' customers were located in these 11 communities. Also served are 279 smaller communities as well as rural areas with a combined population of approximately 701,000. - ATCO Gas distributes natural gas in incorporated communities under the authority of franchises or by-laws and in rural areas under approvals, permits or orders issued through applicable statutes. It currently has 167

	franchise agreements with communities throughout Alberta. These franchise agreements detail the rights granted to ATCO Gas and its obligations to deliver natural gas services to consumers in the municipality. All franchises are exclusive to ATCO Gas and are renewable by agreement for additional periods of up to 20 years.[72] • ATCO Electric - transmits and distributes electricity to 245 communities and rural areas in east-central and northern Alberta. Among those served are the communities of Drumheller, Lloydminster, Grande Prairie and Fort McMurray as well as the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River. AEY serves 19 communities in the Yukon Territory, including the capital city of Whitehorse. NUY and NWT serve 9 communities in the Northwest Territories, including the capital city of Yellowknife. o 564,000 people live in the principal markets for electric utility service by ATCO Electric and its subsidiaries NUY, NWT and AEY. Service is provided to approximately 252,000 customers. ATCO Electric has been assigned about 65% of the designated service area within Alberta. This service area contains approximately 14% of the provincial electrical load and 13% of the population. o ATCO Electric, AEY, NUY and NWT distribute electricity to incorporated communities under the authority of franchises or by-laws; in rural areas, electricity is distributed by approvals, permits or orders under applicable statutes. In Calgary, distribution of natural gas operates under a municipal by-law. The rights of ATCO Gas under this by-law, while not exclusive, are unrestricted as to term. The by-law does not confer any right for Calgary to acquire the facilities used in

	providing the service.[73]
	• ATCO Pipelines – owns and operates extensive gas transmission system and salt cavern storage peaking facility in Alberta. Peak delivery capability is 3.8 Bcf/day
	  o Natural gas transportation rates in Alberta are based on the ATCO Pipelines cost-of-service approved by the AUC plus the NGTL cost-of-service approved by the National Energy Board (NEB).
	• ATCO Gas Australia - provides natural gas distribution services in Western Australia. This subsidiary serves customers in 18 communities, including metropolitan Perth and surrounding regions
	• Growth CAGR
	  o ALB – 1.6%[74]
	• Per Capita Income CAGR
	  o ALB – 4.3%[75]
	• Employment growth
	  o ALB – 1.4%[76]

Residential Retail Unbundling[77]	In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to 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.
Climate	• Natural gas occupies 79%[78] of residential market indicating high heating load.
Supply Availability and Deliverability	• N/A
Competition with other Fuel Sources	• Natural gas has ~79% of residential market share[79]
Competitive Price Advantage[80]	• Natural gas enjoys price advantage
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[81]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. ALB – DBRS 30.5

Regulatory and Legislated Initiatives	• Coal fueled power generation assets in Alberta will be impacted by changing environmental regulations. The federal government of Canada has already released regulations for greenhouse gas emissions that will limit the life of the Company's coal-fired generating plants. ATCO Power estimates that the total capital costs relating to air quality control equipment over the period 2015 to 2017 will be ~ $16 million in order to create emissions credits and achieve compliance with the existing Alberta regulations for NOx and SO2 emissions.[82]
Regulatory Model	• Cost of Service regulatory model – ATCO Gas Transmission, ATCO Electric Transmission, Yukon and Northwest Territories operations, ATCO Gas Australia • Performance Based Ratemaking – ATCO Gas Distribution, ATCO Electric Distribution
Test Year[83]	• Forecast – ATCO Gas, ATCO Electric, ATCO Pipelines • Projected test year for five year period – ATCO Gas Australia
Interim Rates[84]	Routinely allowed – ATCO Gas, ATCO Electric Not allowed – ATCO Gas Australia
Typical Rate Case Lag[85]	ALB – ~12 mos.
Most Recent Authorized ROE[86]	ATCO Gas – 8.30% ATCO Electric – 8.30% ATCO Electric Transmission – 8.30% ATCO Pipelines – 8.30% ATCO Gas Australia – WACC or ROA = 7.75%
Most Recent Authorized Equity Ratio[87]	ATCO Gas – 38% ATCO Electric – 38% ATCO Electric Transmission – 36% ATCO Pipelines – 37% ATCO Gas Australia – 40%
Gas Supply Risk Mitigation and Incentives	Purchased Gas Adjustment Clauses: • N/A ATCO Gas and ATCO Electric have assigned all supply responsibilities to Direct Energy, though they both retain limited POLR obligations[88]
Volume /Demand Risk Mitigation	• Revenue Stabilization o Weather Normalization Deferral Account – ATCO Gas[89] o ATCO Electric Transmission ▪ Transmission costs

	are equalized by having each owner of transmission facilities charge its costs to the Alberta Electric System Operator (AESO). The AESO then aggregates these costs and charges a common transmission rate to all transmission system users.[90]

Capital Cost Recovery Risk Mitigation[91]	• PBR Mechanism provides K-factor to recover significant CAPEX between rebasing – ATCO Gas and ATCO Electric distribution operations.
	• AFUDC – ATCO Electric
	• Established pre-approved capital investment programs
	    o ATCO Electric Transmission - new transmission projects are direct assigned to TFOs based on the service areas of the distribution companies they have been historically affiliated with. Facilities ownership will change at service area boundaries, except where, in the AESO's opinion, only a small portion of the project is in another service area. This rule applies to all transmission projects except interprovincial intertie projects and those deemed "critical" by the Alberta government.
	    o ATCO Gas – Urban Pipeline Replacement Program
	• Capital Trackers – ATCO Gas, ATCO Electric - pending

Other Significant Deferral and Variance Accounts[92]	• PBR Mechanism provides Y-factor to recover or refund annual variances in predetermined deferral and variance accounts – ATCO Gas and ATCO Electric distribution operations.
	    o Site Restoration and Removal Deferral
	    o Load Balancing Deferral
	    o Defined benefit pension plans and OPEB plans
	    o Deferred income taxes
	    o Transmission Access Payments
	    o Direct Assign Capital Variance

	account

Emera (TSX: EMA)

<table>
<tr><th colspan="2">SNL Financial Company Overview[93]</th></tr>
<tr><td colspan="2">Emera Inc. is geographically diverse energy and services company headquartered in Halifax, Nova Scotia with $9.84 billion in assets and 2014 revenues of $2.97 billion. The company invests in electricity generation, transmission and distribution, as well as gas transmission and utility energy services. Emera's strategy is focused on the transformation of the electricity industry to cleaner generation and the delivery of that clean energy to market. Emera has investments throughout northeastern North America, and in four Caribbean countries. Emera continues to target having 75-85% of its adjusted earnings come from rate-regulated businesses.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (BBB+/Stable/--)[94]</th></tr>
<tr><td>Business Risk – Excellent

Emera's "excellent" business risk profile reflects our view of its diversified portfolio of regulated operations in jurisdictions with generally supportive regulatory environment. Approximately 80% of the company's revenues come from rate-regulated subsidiaries, with approximately 60% of consolidated revenues from NSPI alone. NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. Emera's exposure to unregulated revenues is primarily through its 24.3% ownership in Algonquin Power & Utilities Corp., which it accounts for using the equity method, and the recently acquired New England assets that it consolidates. We believe that Emera's regulated revenues could form a greater portion of its total revenues as the Maritime Link project begins operations in 2017. Although we believe that the company will start benefiting from the project once it begins operations, in addition to inherent construction risks associated with a project of this scale, there will be no cash flow from the project during its construction.</td>
<td>Financial Risk – Significant

Emera's "significant" financial risk profile reflects the stability and predictability of the company's regulated cash flow. We project Emera's AFFO-to-debt ratio to range from 12%-13% in the next two years. We have added to the company's consolidated debt C$250 million and C$600 million of debt for 2014 and 2015, respectively, for the Maritime Link project, reflecting the project's importance to Emera and our view that the company would support the project if required.</td></tr>
<tr><th colspan="2">Operating Characteristics</th></tr>
<tr><td>Operations/State/Customers (000's)[95]</td>
<td>• Nova Scotia Power – fully integrated electric utility – 504
• Emera Maine (formerly Bangor Hydro Electric Co. and Maine Public Service Company) provides electric transmission and distribution – 155
• 80.6% interest in Emera Caribbean (formerly Light and Power Holdings – parent of Barbados L&P – vertically integrated electric utility)- 126
• 41.8% interest in Dominica Electricity Services – 35
• 15.4% interest in St. Lucia Electricity Services</td></tr>
</table>

	• 50% direct interest and 30.4% indirect interest in Grand Bahama Power Co. – 19
Total Assets (2014 $CAD billions)[96]	$9.8 billion
% of Operating Revenues in Regulated Distribution Operations (2014)[97]	North American and Caribbean Distribution companies make up 70% of operating revenues; North American distribution operations make up 54% of distribution operations; and NSPI makes up 46% of operating revenues.

Customer Mix (2014)[98]	• NSPI
	  o Electric Revenues (2014)
	    ▪ Residential – 51%
	    ▪ Commercial – 29%
	    ▪ Industrial – 16%
	    ▪ Other – 4%
	• Emera Maine
	  o Electric Revenues (2014)
	    ▪ Residential – 48%
	    ▪ Commercial – 38%
	    ▪ Industrial – 8%
	    ▪ Other – 6%
	• Emera Caribbean
	  o Electric Revenues (2014)
	    ▪ Residential – 33%
	    ▪ Commercial – 59%
	    ▪ Industrial – 6%
	    ▪ Other – 2%

%CAPEX Spend[99]	• Capex plan for 2015 is $1.2 billion, and the utilities portion was $0.456 billion or 37% (Canadian portion – NSPI is $0.273 billion), 2016 is $1.276, the utilities portion was $527 million or 41%, and 2017 was $966 for $471 million or 43%. • Capex for Canadian Distribution operations runs ~$300 million annually
Service Territory	• NSPI – primary electricity supplier in Nova Scotia (has $4.3 billion of assets and provides electricity to 504,000 customers) owns 2,483 MW of generation (50% coal fired, 28% fossil fuel, 19% hydro and wind, 3% biomass)[100] • Emera Maine – T&D utility in Maine (formed by 1/1/2014 merger of Bangor Hydro Electric Co. and Maine Public Service Company) (approximately 48% of revenues are from distribution operations, 33% of revenues are from transmission operations; and 19% from stranded asset recovery.[101] • Bahama economy is highly correlated to US economy.[102] • Barbados economy has been slower to

	rebound since it relies on tourism which is still depressed since the 2008 financial crisis.[103] • Population Growth CAGR o NS – 0.1%[104] o Maine – 0.0%[105] • Per Household Disposable Income o NS – 2.4%[106] o Maine – 2.7%[107] • Employment growth o NS – (0.2)%[108]
Residential Retail Unbundling[109]	Electricity generation is deregulated in Maine, but electric sales pricing is regulated
Climate	• Natural gas occupies1%of residential market in Nova Scotia, electricity makes up 43%, with closest competition from heating oil making up 42%.[110]
Supply Availability and Deliverability[111]	• A large portion of NSPI's fuel supply comes from international suppliers and is subject to commodity price and foreign exchange risk. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. Foreign exchange risk is managed through forward and swap contracts. Fuel contracts may also be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The adoption and implementation of the FAM has helped NSPI further manage this risk.
Competition with other Fuel Sources	• Natural gas occupies1%of residential market in Nova Scotia, electricity makes up 43%, with closest competition from heating oil making up 42%.[112]
Competitive Price Advantage[113]	• Very little natural gas in Nova Scotia and Maine service territories. Main competition is heating oil which is generally less expensive than electricity
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[114]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. Nova Scotia – DBRS 36

	Maine – RRA Ranking Average/2
Regulatory and Legislated Initiatives	• The Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of NSPI customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from Efficiency Nova Scotia, when it is cheaper than generation, on a go-forward basis. The Program Costs are capped for 2015 at $35.0 million. The UARB will provide regulatory oversight of the Program Costs thereafter. The Program Costs for 2015 will be deferred as a regulatory asset and recoverable from customers over an eight year period beginning in 2016. The UARB will determine how the Program Costs will be recovered from customers for 2016 and beyond.[115]

Regulatory Model[116]	• Cost of Service regulatory model –
	    o NSPI, electric rates are subject to UARB approval - not subject to annual review process – but based on periodic hearings as necessary
	    o Emera Maine
	    o Barbados Light & Power
	• Performance Based Ratemaking – Flexible Rate Adjustment Model - Grand Bahama Power Company
	• Earnings Sharing Mechanism - Grand Bahama Power Company

Test Year[117]	• Forecast – NSPI • Historical with known and measurable differences – Emera Maine
Interim Rates	Allowed in certain circumstances - Maine[118] Not allowed – Nova Scotia[119]
Typical Rate Case Lag	Nova Scotia – 6.5 mos[120] Maine – 6 to 9 mos.[121]
Most Recent Authorized ROE[122]	• NSPI – 8.75% to 9.25% • Emera Maine – was 10.2% (effective July 1, 2014 became 9.55%) o Transmission operations ROEs are regulated by FERC and earn incentive returns • Barbados Light & Power – WACC of 10% • Grand Bahama Power Company WACC of

	10%
Most Recent Authorized Equity Ratio[123]	• NSPI – 40% • Emera Maine – was 50% (effective July 1, 2014 became 49%) o Transmission operations common equity components based on most recent 2 year average. • Barbados Light & Power – N/A • Grand Bahama Power Company – N/A
Gas Supply Risk Mitigation and Incentives[124]	Purchased Gas Adjustment Clauses: • NSPI has an annual fuel adjustment mechanism, fuel costs subject to annual audit • Barbados Light & Power – monthly fuel adjustment mechanism • Grand Bahama Power Company – monthly fuel adjustment mechanism
Volume /Demand Risk Mitigation[125]	• Revenue Stabilization o NSPI - Fixed Cost Recovery Deferral – 2012 Large Industrial Customers (recovers lost revenues associated with 2 large customers)
Capital Cost Recovery Risk Mitigation[126]	• AFUDC – NSPI, Emera Maine and GBPC all include an equity component in AFUDC. • Established pre-approved capital investment programs o None noted • Capital Trackers – none noted
Other Significant Deferral and Variance Accounts[127]	• Fixed cost recovery deferral – NSPI defers a portion of fixed cost recovery to future periods (subject to reduction for excess earnings and subject to revenue cap) • Emera Maine – 5 year deferral of $5 million of costs associated with major ice storm • Stranded Asset Recovery – Emera Maine (recovers all prudently incurred costs resulting from restructuring electric industry in 2000) • Restructuring above market PPA – Emera Maine • Pension and post retirement medical plan

Enbridge Inc. (TSX: ENB)

<table>
<tr><th colspan="2">SNL Financial Company Overview[128]</th></tr>
<tr><td colspan="2">Enbridge, a Canadian Company, is a North American leader in delivering energy and has been included on the Global 100 Most Sustainable Corporations in the World ranking for the past six years. As a transporter of energy, Enbridge operates, in Canada and the United States, the World's longest crude oil and liquids transportation system. The Company also has significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in more than 2,200 MW (1,600 MW net) of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal facilities. Enbridge employs more than 11,000 people, primarily in Canada and the United States and is ranked as one of Canada's Top 100 Employers for 2014.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (A-/Stable/A-2)[129]</th></tr>
<tr><td>Business Risk – Excellent

We view Enbridge's business risk as "excellent," with an "excellent" competitive position. The company generates a significant portion of its cash flow through tolls on the liquids pipelines and earnings from regulated gas distribution. Although the competitive tolling settlement expose Enbridge to a higher degree of volume risk, the fundamentals of increasing Alberta crude oil production and constrained export capacity bode well for seeing volumes remain strong. The company does not take direct commodity risk on the pipelines, and the contract profile is long-term with generally creditworthy counterparties. We expect new projects to feature long-term contracts that limit volume risk, with no commodity exposure that generate stable cash flows. Gas distribution accounts for approximately 15% of cash flow, and we believe consistent and predictable regulation, commodity cost pass-through, and a demonstrated ability to earn the allowed return on equity established by the regulator support the excellent competitive position.</td><td>Financial Risk – Significant

We view Enbridge's financial risk profile as "significant". A very large capital program to expand existing and build new liquids pipelines will pressure financial metrics for the next several years. We expect that there will be very limited headroom above our 13% AFFO-to-debt downgrade threshold, and that financial policy, including the mix of external financing and dividend growth, will be crucial to maintaining the rating.</td></tr>
<tr><th colspan="2">Operating Characteristics</th></tr>
<tr><td>Operations/State/Customers (000's)[130]</td><td>Operating segments are liquids pipelines (38% of total assets); gas distribution (13% of total assets); gas pipelines, processing and energy services (10% of total assets); sponsored investments (32% of total assets); and corporate (7% of total assets).
• EGDI – 2,000
• Enbridge Gas New Brunswick - 11[131]</td></tr>
<tr><td>Total Assets (2014 $CAD billions)[132]</td><td>$72.9 billion</td></tr>
<tr><td>% of Assets in Regulated Distribution Operations (2014)[133]</td><td>Gas distribution operations assets are 9.3 billion or 13%. Gas distribution makes up 9% of revenues and 13% of operating income.</td></tr>
</table>

Customer Mix (2014)[134]	• EGDI Revenues (2014)
	  o Residential – 33%
	  o Commercial – 27%
	  o Industrial – 23%
	  o Wholesale – 16%

%CAPEX Spend[135]	• A key focus of Enbridge's corporate strategy is the successful execution of its growth capital program. In 2014, Enbridge successfully placed into service approximately $10 billion of growth projects across several business units. Enbridge also expanded its portfolio of commercially secured growth projects to $34 billion. All of these projects are expected to come into service by 2018; with more than $9 billion during 2015. • Capex for Canadian Distribution operations was $663 million for 2014; and is forecast at $1 billion for 2015. The average in recent years has been $527 million.[136]

Service Territory	• EGDI serves over 2 million customers in central and eastern Ontario, including the metropolitan area of Toronto and surrounding regions and some areas in Northern New York through St. Lawrence.[137]
	• Utility business is conducted under statutes and municipal bylaws which grant the right to operate in areas served.[138]
	• Company owned and operated a network of 37,600 kilometers of mains for its gas distribution system.[139]
	• New customer additions remains strong in 2014 with 34,839 customers added in 2014.[140]
	• Average use per customer is increasing in EGDI's service territory from 2012-2014.[141]
	• Population Growth CAGR
	  o ONT – 1.2%[142]
	• Per Household Disposable Income
	  o ONT – 3.8%[143]
	• Employment growth
	  o ONT – 1.0%[144]

Residential Retail Unbundling[145]	Customers have a choice with respect to natural gas supply. One option is a sales service option, whereby the customer purchases natural gas from the Company's supply portfolio (system supply). The Company does not earn a margin on the natural gas commodity it provides to customers. Alternatively, a

	natural gas user may select a direct purchase option, which is a transportation service arrangement. Under the transportation service arrangement, a customer supplies natural gas at a TransCanada Pipelines Limited (TransCanada) receipt point in western Canada or at a TransCanada delivery point in Ontario, and the Company redelivers an equivalent amount of natural gas to the customer's end-use location. As a third option, a customer may select an unbundled service arrangement. Similar to the transportation service arrangement, customers deliver their own natural gas into the Company's distribution system, but they are responsible for balancing consumption with deliveries on a daily basis. These arrangements are billed by the Company under the OEB approved rate schedules.
Climate	Natural gas occupies 66% of residential market in Ontario, with electricity making up 23%, heating oil 4%, wood 5%, and other 2%.[146]
Supply Availability and Deliverability[147]	• EGDI owns rate regulated and non-regulated natural gas storage facilities in Ontario.[148] • EGDI maintains a diversified natural gas supply portfolio. During the year ended December 31, 2014, the Company acquired approximately 9.1 billion cubic metres of natural gas (2013 - 7.8 billion cubic metres), of which 58% (2013 - 47%) was acquired from western Canadian producers, 17% (2013 - 23%) was acquired from suppliers in Chicago and 25% (2013 - 30%) was acquired on a delivered basis in Ontario. The Company also transported 4.7 billion cubic metres (2013 - 4.7 billion cubic metres) of natural gas on behalf of direct purchase customers operating under a transportation service arrangement. The Company's system supply natural gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts may be indexed to Alberta, Chicago or New York based prices. • TransCanada transports approximately 69% or 9.1 billion cubic metres (2013 - 60% or 7.4 billion cubic metres) of the annual natural gas supply requirements of the Company's customers.
Competition with other Fuel Sources	• Natural gas enjoys a price advantage over other fuels in Ontario.[149] • Natural gas is the predominant fuel of

	choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue.[150]
Competitive Price Advantage[151]	• During 2014, natural gas in the residential market experienced, on average, a price advantage on an energy equivalent basis of 65% (2013 - 69%) against electricity and 67% (2013 - 71%) against domestic fuel oil
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[152]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. Ontario – DBRS 33 New Brunswick – DBRS 30 Quebec – DBRS 38 New York – RRA Ranking Average/2
Regulatory and Legislated Initiatives	• Ontario is a signatory to the Western Climate Initiative. Ontario is currently developing a carbon management strategy which will be released in 2015. The Company reports greenhouse gas (GHG) emissions from combustion sources only in Ontario, and all reported data is verified by a third party. There were no issues identified for the 2014 reporting year. [153] • Government of New Brunswick enacted legislation that in 2011 permitted the government to change the franchise agreement between EGNB and the province. According to the new legislation, EGNB no longer met criteria for rate regulated accounting and was forced to write off $262 million of regulatory assets. The new regulation changed the regulatory model in New Brunswick to lower of cost of service or market. Legal proceedings are ongoing.[154]
Regulatory Model[155]	• EGDI- rates are updated annually (including ROE) o Performance Based Ratemaking o Earnings Sharing Mechanism o Incentive Mechanism that allows the company to earn above its allowed return. • Enbridge Gas New Brunswick

	o Lower of cost of service or market-based rates
Test Year[156]	• Forecast – EGDI (billing determinants and ROE are updated annually) o St. Lawrence rates set by cost of service
Interim Rates	Allowed through Revenue Adjustment deferral account for EGDI[157]
Typical Rate Case Lag	EGDI has formula rates for 5-year period, typically cases are decided within 8 months[158]
Most Recent Authorized ROE[159]	• EGDI – 9.36% o St. Lawrence – 10.5%[160]
Most Recent Authorized Equity Ratio[161]	• EGDI – 36% o St. Lawrence – 50.0%[162]
Gas Supply Risk Mitigation and Incentives[163]	Purchased Gas Adjustment Clauses: • EGDI – has quarterly fuel adjustment through QRAM mechanism, difference between actual and forecast fuel prices are recovered over subsequent 12 month period, sometimes collections are deferred beyond one year[164]
Volume /Demand Risk Mitigation[165]	• Revenue Stabilization o EGDI – Average use true up account mitigates volume differences for residential customer class – industrial and commercial customers are at risk for actual volumes that differ from forecast volume.
Capital Cost Recovery Risk Mitigation	• EGDI may capitalize IDC only (i.e. no equity component)[166] • Established pre-approved capital investment programs[167] o Greater Toronto Area (GTA) project – OEB approval received in January 2014 - $756 million to be completed in 2015. o St. Lawrence Gas expansion (received regulatory approval in July 2012) – expected to be completed in 2018. Total capital cost is $52 million. • Capital Trackers[168] o Rate plan includes core capital allocation to meet customer growth and integrity management programs (averaging approximately $440 million/year through 2018)

	o GTA Project DVA account
Other Significant Deferral and Variance Accounts[169]	• EGDI o Customer care mechanism o DSM mechanism o Greenhouse Gas Emissions Deferral account[170] o Pension and other OPEB mechanism o Constant dollar net salvage adjustment o Unabsorbed demand cost o Design day criteria transportation o DSM management incentive o Deferred rate hearing costs o Future removal and site restoration o Storage and transportation o Transactional services deferral o Revenue adjustment mechanism (adjusts for interim rates) • Z factor approved for material unforeseen events (i.e. > $1.5 million)

Valener Inc. (TSX: VNR)

<table>
<tr><th colspan="2">SNL Financial Company Overview[171]</th></tr>
<tr><td colspan="2">Valener is a public company that is 100% owned by the public investor and serves as the investment vehicle in Gaz Métro. Through its investment in Gaz Métro, Valener offers its shareholders a solid investment in a diversified and largely regulated energy portfolio in Quebec and Vermont. As a strategic partner, Valener, on one hand, contributes to Gaz Métro's growth, and on the other hand invests in wind power production in Quebec together with Gaz Métro. Valener favors energy sources and uses that are innovative, clean, competitive and profitable.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (BBB+/Stable/--)[172]</th></tr>
<tr><td>Business Risk – Strong

The "strong" business risk profile reflects the inherent link to GMLP, as well as our opinion of the highly stable underlying nature of the cash flows at the GMLP level. We base our assessment of Valener's business risk on GMLP's underlying regulated natural gas distribution businesses in Quebec and Vermont, as well as its regulated electric transmission and distribution assets in Vermont. GMLP also has interests in the Seigneurie de Beaupre wind power projects. We expect residual cash flows from wind power to be more volatile than those from regulated gas distribution due to the nature of wind generation. In our view, the relationship between GMLP and Valener is key to the ratings. Valener has no direct operations or staff, and is managed by GMLP pursuant to a management and administration support agreement. Three of its five board members are also on the GMLP board, and its stated strategy is to maintain its 29% proportional interest in GMLP as it increases in overall size. GMLP has supported Valener, providing an additional C$20 million in distributions to support
its dividends in the past. Our base-case operating scenario forecasts no change in the relationship between the two entities, and no change in Gaz Metro's or Valener's dividend policy.</td><td>Financial Risk – Significant

Valener's significant financial risk profile reflects our view of the company's degree of leverage and future financing needs. Valener receives distributions from GMLP, and accounts for its interest as equity. The distributions reflect residual cash flows from GMLP after it has satisfied its own financing needs. Pursuant to the partnership agreement, GMLP has to distribute at least 85% of its net income, excluding nonrecurring items. Any distributions less than 85% will require 90% approval from GMLP's board, which provides an effective veto to the three Valener directors nominated to the board. GMLP is distributing above this level, so we view this as a lower limit to cash flows at Valener, recognizing the fact that earnings are variable.</td></tr>
<tr><th colspan="2">Operating Characteristics</th></tr>
<tr><td>Operations/State/Customers (000's)[173]</td><td>Valener owns a 29% interest in Gaz Metro Limited Partnership. In addition to distribution facilities listed below, Gaz Metro owns a 50% interest in TQM, that connects to TCPL, owns Champion (2 pipelines that cross the Ontario border and supply the northwest corner of Gaz Metro's distribution system); and owns at 38.3% interest in PNGTS (starts at the Quebec border and serves Boston); As well, Gaz Metro owns interests (51%) in wind farms (272MW sold to HQ), Valener owns the remaining 49%. Also has an energy services division that includes Gaz Metro LNG (ensures the liquefaction capacity of Gaz Metro's LSR plant and</td></tr>
</table>

	the new LNG plant to be constructed); and transport solution, providing CNG and LNG for fleet transportation fuels. Energy distribution accounted for 97% of Gaz Metro's net income, with Gaz Metro accounting for 66% of distribution net income. • Gaz Metro – 2,000 • VGS – 45 • GMP – o MOU upon acquisition of CVPS, that GMP must generate at least US$144 of synergy savings for its customers over a 10 year period. Schedule of payments to customers is as follows: ▪ Fixed amounts 2013-2015 (2014 $5 million, 2015 $8 million) ▪ Shared equally 2016-2020 ▪ 100% to customers 2021-2022
Total Assets (2014 $CAD billions)[174]	$0.815 billion Valener $6.144 billion Gaz Metro Limited Partnership
% of Assets in Regulated Distribution Operations (2014)[175]	Energy distribution assets are 84% of total Gaz Met partnership assets. Gaz Metro distribution makes up 46% of total energy distribution assets.
Customer Mix (2014)[176]	• Gaz Metro Normalized Gas Volume (2014) (10^6m^3) o Industrial ▪ Firm – 2,983 (50%) ▪ Interruptible –498 (8%) o Commercial – 1,846 (31%) o Residential – 673 (11%) • Gaz Metro electricity distribution (gigawatt hours) o Residential – 1,558 (36%) o Small commercial and industrial (37%) o Large commercial and industrial – 1170 (27%) • Gaz Metro's major customers (numbering over 200) comprise 52% of natural gas deliveries and 22% of total revenues.
%CAPEX Spend[177]	CAPEX for remainder of 2015 ~$227 million • CAPEX of ≈ $180M for extensions and improvements to energy distribution systems o Gaz Métro - QDA: ≈ $80M o VGS & GMP: ≈ $100M

	• CAPEX of ≈ $47M for LSR plant expansion (total cost of LSR Plant expansion is $118 million)[178] • VGS system expansion total cost $121.6 million

Service Territory[179]	• Energy Distribution segment consist of natural gas distribution activities in Quebec and Vermont as well as electricity distribution in Vermont.
	    o Gaz Metro services 97% of the natural gas consumed in Quebec.
	    o VGS is the sole gas distributer in VT serving over 45,000 mainly residential and commercial customers.
	    o GMP is Vermont's largest electricity distributor, serving more than 70% of the market and about 260,000 customers – system is mostly located in Vermont but extends to NY and New Hampshire.
	• Gaz Metro number of customers served increased 1.4% between 2013 and 2014; and its normalized natural gas deliveries increased by 3.7%.
	• Population Growth CAGR
	    o QC – 0.7%[180]
	    o VT – 0.1%[181]
	• Per Household Disposable Income
	    o QC – 3.0%[182]
	    o VT – 3.6%[183]
	• Employment growth
	    o QC – 0.5%[184]

Residential Retail Unbundling[185]	Gas market restructuring and retail competition has not occurred in Gaz Metro's gas service territories in Quebec or Vermont.
Climate	• Natural gas occupies 7% of residential market in Quebec, with electricity making up 69%, heating oil 8%, and wood 15%.[186]

Supply Availability and Deliverability[187]	• Gaz Metro relies on a varied portfolio of transportation and storage with differing expirations to meet its delivery requirements.
	    o Firm capacity on TCPL that delivers from Western Canada or from Dawn.
	    o Contracts for storage capacity in Quebec and at Dawn in Ontario.
	    o Gaz Metro buys natural gas required to supply customers.
	    o Supply plan submitted to Régie

	once a year for approval. Régie recently approved request to move supply receipt point from Empress to Dawn (closer and takes better advantage of cheap and abundant U.S. supply) • TransCanada has recently filed (2014) a case to convert a portion of their gas mainline to a liquids pipeline transporting oil from western to eastern Canada which may pose a supply risk to the utilities in eastern Canada. • GMP's supply portfolio consists of multiple generation sources, mainly hydro and to a lesser degree, nuclear and wind. Owns commercial scale wind farm ~70 MW – largest wind producer in the state. • New England electric power market continues to have adequate supply to meet demand in the region, but pipeline capacity gets constrained in the winter months.
Competition with other Fuel Sources[188]	• Electricity has the largest residential market share in Quebec for historical reasons and as a result, natural gas faces strong competition in the residential market. • Even though natural gas is cheaper than electricity, the cost gap is narrow for customers comparing a standard gas furnace to high efficiency electric heating system. • Environmental benefits of natural gas are helping to drive growing demand in North America. • In Quebec, natural gas is the most competitive form of energy among all those distributed in the market. • This is expected to persist despite the developing carbon market in Quebec. • In Vermont, natural gas has a significant advantage over other energy sources in the air and water heating markets. Natural gas is used for heating in most residences and is more than 40% to 50% less expensive than oil and propane, respectively. Electricity is primarily used for generating and lighting purposes.
Competitive Price Advantage[189]	• The economic price advantage of natural gas has grown out of shale boon in U.S. • Currently (2015), natural gas in the residential market experienced, on average, a price advantage on an energy equivalent basis of 9% to 25% against electricity and 8% to 24% against domestic No. 2 fuel oil; the large industrial market experienced a

	19% advantage over closest competitor No. 6 fuel oil; natural gas in the commercial market experienced, on average, a price advantage on an energy equivalent basis of 21% (small commercial) to 42% (large commercial) against electricity and 26% (small commercial) to 45% (large commercial) against No. 2 fuel oil.
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[190]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. Quebec – DBRS 38 VT – RRA Ranking Average/3
Regulatory and Legislated Initiatives[191]	• Gaz Metro is subject to the CATS (carbon cap and trade market) Regulation as of January 1, 2015. Gaz Metro will be required to reduce emissions and to purchase GHG emissions allowances. This regulation replaces annual duty under the Green Fund. Estimated compliance costs for 2015 are $45 million and over $70 million for 2016. • Climate Change Action Plan 2013-2020 to reduce reliance on fossil fuels. Government actions will focus on transportation, industry and buildings. • Government of Quebec biomethanation program – Gaz Metro plans on providing biomethane in 2015. • Vermont encourages development of renewable energy resources – 20% statewide electricity sales be generated with renewable electricity. • GMP participates in RGGI, multi state cap and trade program, GMP has one plant subject to compliance and costs to comply are low and expected to remain so.
Regulatory Model[192]	• Distribution rates are set by cost of service method – Gaz Metro, VGS, GMP • GMP has alt reg plan which includes earnings, sharing, power supply adjustment mechanism, and a formula ROE. Alt reg plan commenced January 2014 and will be in effect for 3 years. • Earnings sharing – Gaz Metro, GMP • Performance Incentives for energy savings – Gaz Metro $1 million (GEEP).
Test Year[193]	• Forecast – Gaz Met • Historical Average rate base with adjustment

	for known and measurable differences – VGS, GMP
Interim Rates[194]	Régie approved an interim distribution rate based on a 1.8% inflation rate that will go into effect January 1, 2015 and will remain until decision is reached on Phase III of the 2015 rate case.
Typical Rate Case Lag	QC - ~ 7 mos[195] VT – 8 mos[196]
Most Recent Authorized ROE[197]	• Gaz Metro – 8.9% (9.25% earned) • VGS – 10.20% • GMP – 9.6%
Most Recent Authorized Equity Ratio[198]	• Gaz Metro – 38.5% • VGS – 55% equity • GMP – 50% equity
Gas Supply Risk Mitigation and Incentives[199]	Purchased Gas (or Fuel) Adjustment Clauses: • Quarterly adjustment mechanism – VGS, GMP
Volume /Demand Risk Mitigation[200]	• Revenue Stabilization o Gaz Metro – weather normalization (based on normal temperature and wind velocity) deferral adjustment; recovered from/returned to customers over 5-year period. o VGS – weather normalization o GMP – Alt Reg Plan mitigates how certain volume/cost variations due to weather impact earnings.
Capital Cost Recovery Risk Mitigation[201]	• Gaz Met capitalizes AFUDC at its WACC. • Established pre-approved capital investment programs[202] o LSR facility expansion – Gaz Metro o System expansion -VGS • Capital Trackers o None noted
Other Significant Deferral and Variance Accounts[203]	• Gaz Metro o Green fund surcharge – Gaz Metro o Bad debt deferral account – Gaz Metro o Energy efficiency-Gaz Metro, GMP o Pensions and OPEB – Gaz Metro, GMP o Grants paid – Gaz Metro, VGS o Inventory stabilization- Gaz Metro

	o Site decontamination and dismantling costs – VGS, GMP o Deferred vacation – Gaz Metro o Storm costs – GMP o System expansion and reliability fund – VGS o Future costs of retiring PP&E – Gaz Metro

Union Gas Ltd.

<table>
<tr><th colspan="2">SNL Financial Company Overview[204]</th></tr>
<tr><td colspan="2">Union Gas Limited is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves about 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' storage and transmission business offers a variety of storage and transportation services to customers at the Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America. The Dawn Hub offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada and the northeast U.S. Union Gas, one of Canada's Top 100 Employers for 2014, is a Spectra Energy (NYSE: SE) company with assets of $6.4 billion and approximately 2,200 employees.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (BBB+/Stable/A-2)[205]</th></tr>
<tr><td>Business Risk – Excellent

We view Union's business risk profile as "excellent," with an "excellent" competitive position that reflects its efficient regulated gas distribution network, attractive franchise region in Ontario, strategic ownership of natural gas storage and transmission assets in southern Ontario, and a regulatory mechanism that allows for a complete flow-through of commodity cost expense to customers and permits the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates Union Gas' distribution operations under an incentive-based regulatory model from 2014 -2018. We view the regulatory environment as generally stable and transparent, and we expect that the company will be able to achieve the expected productivity gains and earn its previously allowed ROE at a minimum. Although more than 80% of Union Gas' revenue comes from regulated distribution business, and regulated storage accounts for about another 10% of revenue, the company has an unregulated storage business (about one-third of total storage capacity) that can introduce some earnings volatility and alter its business risk profile. Seasonal storage spreads have been weak through 2013, and we expect that to continue for the next 12-24 months. The storage and transmission assets enhance operating flexibility and enable Union Gas to manage its gas inventories, providing the benefit of supply security, but the unregulated storage assets are subject to market rates and market demand and can affect earnings.</td><td>Financial Risk – Intermediate

We assess Union Gas' financial risk profile as "intermediate." We forecast that AFFO-to-debt will be approximately 13% during our two-year outlook horizon. We expect capital expenditures to be slightly higher than average in 2014 and 2015 as Union Gas expands its distribution infrastructure.</td></tr>
<tr><th colspan="2">Operating Characteristics</th></tr>
<tr><td>Operations/State/Customers[206]</td><td>1.4 million customers in Ontario</td></tr>
<tr><td>Total Assets (2014 $CAD billions)[207]</td><td>$7.045 billion distribution operations</td></tr>
<tr><td>% of Assets in Regulated Distribution Operations (2014)[208]</td><td>Energy distribution comprised 73% of revenues in 2014; storage and transportation revenue made up the other 27%. In 2013, approximately 97% of</td></tr>
</table>

	Union Gas assets appeared in the OEB distributor's yearbook, indicating they were subject to regulation. Assuming the same hold true for 2014.[209]
Customer Mix (2014)[210]	Customer mix (> 50 cubic meters per year>) • Low volume customers 1,227,681 ~99.6% • Large volume customers 5,236 Throughput • 2014 Distribution volumes (106m3)= 14,748 ~43% • 2014 Transportation volumes (106m3)=19,696 ~57%
%CAPEX Spend[211]	Over $2 billion in Ontario infrastructure expansion planned between 2015 and 2018.
Service Territory	• The distribution business serves about 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario.[212] • Operate under legislation and municipal law that grants right to operate in franchise areas served. The OEB has the authority to approve and renew franchise agreements and certificates of public convenience and necessity, which entitle us to construct facilities and operate within our franchise area.[213] • Population Growth CAGR o ONT – 1.2%[214] • Per Household Disposable Income o ONT – 3.8%[215] • Employment growth o ONT – 1.0%[216]
Residential Retail Unbundling[217]	Customers have a choice with respect to natural gas supply.
Climate	Natural gas occupies 66% of residential market in Ontario, with electricity making up 23%, heating oil 4%, wood 5%, and other 2%.[218]
Supply Availability and Deliverability[219]	• The gas supply portfolio of Union Gas primarily includes gas supply purchase contracts that are typically based on an index, depending on where Union Gas sources natural gas from across North America. This includes, but is not limited to, indices such as NYMEX, Alberta, and Chicago.[220] • It is our expectation that demand for natural gas in North America will continue to have low annual growth over the long-term with continued growth in peak day demands.

	However, the development of the Marcellus and Utica Shale areas is leading to significant new pipeline infrastructure to connect these supplies to the North American pipeline grid and the associated natural gas consuming market areas. The proximity of our storage and transportation facilities and our interconnections with major U.S. markets in the Great Lakes region and in the northeast U.S., support long-term growth opportunities. These opportunities focus on connecting new supply sources to Dawn and ensuring that there is sufficient transportation capacity on Union's transmission system and pipelines downstream of Parkway to serve eastern Canadian and U.S. markets. • TransCanada has recently filed (2014) a case to convert a portion of their gas mainline to a liquids pipeline transporting oil from western to eastern Canada (Energy East Project) which may pose a supply risk to the utilities in eastern Canada.
Competition with other Fuel Sources[221]	• Union Gas is not generally subject to third-party competition within its distribution franchise area. However, physical bypass of Union Gas' system may be permitted, even within Union Gas' distribution franchise area. In addition, other companies could enter Union Gas' markets or regulations could change. • Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, and other factors. • The OEB does not regulate long term storage service, which has created an unregulated storage operation within Union Gas, where it must compete with other merchant storage providers.
Competitive Price Advantage[222]	• We expect that the long-term demand for natural gas in Ontario will remain relatively stable with continued growth in peak day demands. Some modest growth driven by low natural gas prices is expected to continue, with specific interest coming from

	communities that are not currently serviced by natural gas, given the significant price advantage relative to their alternate energy options.
Regulatory Environment	
RRA Ranking (as available)/ DBRS Ranking[223]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "-" DBRS Ranking out of 50, higher is better. Ontario – DBRS 33
Regulatory and Legislated Initiatives[224]	• The province of Ontario is operating with a large financial deficit and significant spending commitments. As such, it is expected that the current provincial Government may look for new sources of revenues including non-tax revenue streams such as fees and levies. At this time, we do not anticipate any material financial impact to Union Gas.
Regulatory Model[225]	• Distribution rates are set under a 5-year incentive regulation framework, setting rates each year based on a pricing formula. • Incentive plan for DSM • Earnings sharing mechanism
Test Year	• Test year was approved rates for 2013 with some adjustments[226]
Interim Rates	Quarterly revenue adjustment mechanism[227]
Typical Rate Case Lag	Typically cases are decided within 8 months, N/A during IR period[228]
Most Recent Authorized ROE[229]	ROE is set at 8.93 (2013 allowed return) for duration of IR term and subject to earnings sharing mechanism
Most Recent Authorized Equity Ratio[230]	Equity ratio is 36%
Gas Supply Risk Mitigation and Incentives[231]	Purchased Gas Adjustment Clauses: • Union Gas – has quarterly fuel adjustment through QRAM mechanism, difference between actual and forecast fuel prices are recovered over subsequent 12 month period, sometimes collections are deferred beyond one year
Volume /Demand Risk Mitigation[232]	• Revenue Stabilization o Union Gas – rate increases or decreases in small volume customer classes where average use declines or increases– industrial and commercial customers are at risk for actual

	volumes that differ from forecast volume.

Capital Cost Recovery Risk Mitigation	• Union may capitalize IDC only (i.e. no equity component)[233]
	• Established pre-approved capital investment programs[234]
	  o Parkway Project – OEB approval received in January 2014 - $327 million to be completed in 2015.
	  o Brantford-Kirkwall pipeline and ancillary facilities (received regulatory approval in January 2014) – expected to be completed in 2015. Total capital cost is $116 million.
	  o Dawn to Parkway 2016 Expansion Project, total capital cost $416 million, OEB approval is pending.
	  o Burlington-Oakville Pipeline – to be in service 2016, total cost $120 million, OEB approval is pending.
	• Capital Trackers[235]
	  o Y factor for Major Capital Projects the Brantford-Kirkwall and Parkway D Compressor and the Parkway West projects (EB-2013-0074 and EB- 2012-0433) as filed meet the criteria

Other Significant Deferral and Variance Accounts[236]	• Union Gas
	  o DSM mechanism
	  o Equal sharing of tax changes
	  o Deferral for unaccounted for gas
	• Z factor approved for material unforeseen events (i.e. > $4.0 million)[237]

Atmos Energy Corporation (NYSE: ATO)

SNL Financial Company Overview[238]

Atmos Energy Corporation, headquartered in Dallas, is one of the country's largest natural-gas-only distributors, serving over three million natural gas distribution customers in over 1,400 communities in eight states from the Blue Ridge Mountains in the East to the Rocky Mountains in the West through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Atmos Energy also manages company-owned natural gas pipeline and storage assets, including one of the largest intrastate natural gas pipeline systems in Texas and provides natural gas marketing and procurement services to industrial, commercial and municipal customers primarily in the Midwest and Southeast.

S&P Ratings Summary (A-/Stable/A-2)[239]

Business Risk – Excellent

We assess Atmos' business risk profile as "excellent," incorporating the company's regulated, low operating risk natural gas transmission and distribution operations that benefit from generally constructive regulatory frameworks in their regions of operation. Many, but not all, of these jurisdictions provide for the use of weather-normalization clauses, annual rate stabilization mechanisms, and accelerated capital recovery mechanisms, all of which lend support to cash flow stability. Our assessment of business risk also accounts for Atmos' large customer base of more than 3.2 million customers across multiple states, although the Texas operations represent about two-thirds of total operating income. At the same time, our assessment of business risk incorporates the impact of Atmos' retail gas marketing operations, which we view as having higher business risk and whose contribution should decline over time because Atmos is targeting most of its planned capital spending for the regulated utility operations. Importantly, we expect that Atmos will continue to maintain rigorous risk management practices for its retail gas marketing operations, including prompt hedging of all retail gas supply load commitments, helping to limit exposure to market prices, and maintaining contracts with short-term tenors, enabling the company to re-price or exit potentially unfavorable transactions thereby minimizing losses. On an ongoing basis, we expect that the unregulated business will contribute less than 5% of total operating income and this contribution will decline over time as the regulated part of the company continues to grow.

Financial Risk – Significant

We assess Atmos' financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base case scenario, we expect that Atmos will comfortably maintain its "significant" financial risk profile, with FFO/debt that averages about 21% and debt/EBITDA that averages 3.5x. At the same time, we expect that Atmos will continue to effectively manage its liquidity needs in light of the unregulated operations. The company's robust credit protection measures benefit from the constructive regulatory frameworks under which Atmos operates and which provide for timely recovery of approved invested capital, absent which the financial risk profile would weaken given Atmos' large planned capital spending program.

Operating Characteristics	
Operations/State/Customers (000's)[240]	• Atmos Energy Corp. TX - 1,880 • Atmos Energy Corp. CO - 112 • Atmos Energy Corp. KS - 130 • Atmos Energy Corp. TN - 133 • Atmos Energy Corp. VA - 23 • Atmos Energy Corp. LA - 347 • Atmos Energy Corp. MS - 260 • Atmos Energy Corp. KY - 175
Total Assets (2011-2013 Average $ millions)	$7,573[241]
% of Assets in Regulated Distribution Operations (3-yr Avg)	98.00% (70% of regulated assets are in TX)[242]
Customer Mix (2013)	Gas sales breakdown for 2013: 65%, residential; 29%, commercial; 4%, industrial; and 2% other.[243]
CAPEX Spend	Total CAPEX spend 2014 - $835.3 million (all utilities), 2015 estimated at $900 to $1B, 2016-2018 estimate of $900 to $1.1B/year (91% Fiscal 2015 CAPEX begins earning a return 6 mos. after end of test year)[244]
Service Territory[245]	• Includes Major Metropolitan Areas o TX (Dallas), CO (Denver), LA (New Orleans), MS (Jackson)[246] • Population Growth CAGR 2009-2013 o CO – 1.5% o KS – 0.5% o KY – 0.4% o LA – 0.7% o MS – 0.3% o TN– 0.7% o TX – 1.6% o VA – 1.0% • Per Capita Income CAGR 2009-2013 o CO – 3.1% o KS – 3.5% o KY – 2.9% o LA – 3.1% o MS – 2.9% o TN– 3.5% o TX – 4.4% o VA – 2.6%
Residential Retail Unbundling[247]	• Utilities may offer choice programs, but Atmos has not proposed a program – CO, KY, VA • No customer choice –KY, LA, MS, TN, TX

Climate[248]	• Heating load accounts for approx. 50% of energy bill – CO, KS • Average weather 25%-35% spent on heating – KY, VA, TN, MS • Warmer than normal l~22-25%% spent on heating – TX, LA
Supply Availability and Deliverability[249]	• Natural gas is plentiful and cheap; no delivery constraints noted
Competition with other Fuel Sources[250]	• Approximately 75% of households use natural gas for heating – CO • Approximately 60% of households use natural gas for heating – KS • Natural gas is used ~ 33% of time for heating – VA, TN, KY, MS • Natural gas is used ~ 42% of time for heating – TX, LA
Competitive Price Advantage[251]	Natural gas enjoys significant price advantage in all jurisdictions across all customer classes (between 1/3 and ¼ of electric price)
Regulatory Environment	
RRA Ranking[252]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " • TX – Average/3 • CO - Average/1 • KS - Average/2 • TN - Average/1 • VA - Above Average/2 • LA - Average/1 • MS - Above Average/3 • KY - Average/1
Regulatory Model[253]	Cost of Service – CO, KS, TN, VA, KY Formula Rate Plan (annual rate mechanism) – LA, TX, MS Earnings sharing mechanism - LA[254]
Test Year[255]	Forecast – TN, MS, KY Historical (known and measurable changes) – TX, CO, KS, VA, LA (some partially forecast)
Interim Rates[256]	Allowed on an emergency basis – TX, CO, KS, TN, LA, KY Routinely allowed – VA Not allowed – MS

Typical Rate Case Lag[257]	• TX – Mid-Tex 6 mos, West-Tex 3 mos. • CO – 10 mos. • KS - 7 mos. • TN - 4 mos. • VA - N/A • LA - 10 mos. • MS - 3 mos. • KY - 11 mos.
Most Recent Authorized ROE[258]	• Mid-Tex Cities SOI & Environs – 10.5% (2012) • West TX Division – not provided (2014) • CO – 9.72% (2014) • KS - 9.10% (2014) • TN - 10.10 (2012) new filing pending – requested 10.7% (2014) • VA - 9.75% (2014) • LA - 9.8% (2014) • MS - 9.98% (2015) • KY - 9.8% (2014) • Company's actual earnings were 9.9% in 2014 and 9.7% in 2013.[259]
Most Recent Authorized Equity Ratio[260]	• Mid-Tex Cities SOI & Environs – 52% (2012) • West TX Division – not provided (2014) • CO – 52% (2014) • KS - 53% (2014) • TN - 51% (2012) new filing pending – requested 56% (2014) • VA - 54% (2014) • LA - 51% (2014) • MS - 55% (2015) • KY - 49% (2014)

Gas Supply Risk Mitigation and Incentives[261]	• Purchased Gas Adjustments
	  o Monthly – TX, KS, TN, VA, LA, MS
	  o Quarterly - KY
	  o Annually - CO
	• Gas Supply Incentive Mechanisms
	  o KY, TN, MS[262]
	• Gas Supply Margin Sharing
	  o TN, KY

Volume /Demand Risk Mitigation	• Revenue Stabilization[263] o Base charge covers 64% of LDC cost of service (Approximately 79% in Mid-Tex) • Weather Normalization – covers 97% of revenues[264]

Capital Cost Recovery Risk Mitigation	• CWIP allowed in rate base for return - TN • Established pre-approved infrastructure replacement programs – Mid-Tex and West Texas (Rule 8.209), MS, LA (RSC Infrastructure), KY (PRP), VA (SAVE)[265] • Capital Trackers – TX, KS, LA, KY, VA (45% of Capex has no regulatory lag)[266]
Other Significant Deferral and Variance Accounts[267]	• Pension – LA, MS • Energy Efficiency – TX, CO, VA, KY • Merger and Acquisition Costs (no return) • Environmental Compliance –TN • Bad Debt Rider – KS, KY, TN, VA, TX[268]

New Jersey Resources Corp. (NYSE: NJR)

<table>
<tr><th colspan="2">SNL Financial Company Overview[269]</th></tr>
<tr><td colspan="2">New Jersey Resources (NYSE: NJR) is a Fortune 1000 company that provides safe and reliable natural gas and clean energy services, including transportation, distribution and asset management. With annual revenues in excess of $3 billion, NJR is comprised of five primary businesses: New Jersey Natural Gas is NJR’s principal subsidiary that operates and maintains over 7,000 miles of natural gas transportation and distribution infrastructure to serve over half a million customers in New Jersey’s Monmouth, Ocean and parts of Morris, Middlesex and Burlington counties. NJR Energy Services manages a diversified portfolio of natural gas transportation and storage assets and provides physical natural gas services and customized energy solutions to its customers across North America. NJR Clean Energy Ventures invests in, owns and operates solar and onshore wind projects with a total capacity of over 125 megawatts, providing residential and commercial customers with low-carbon solutions. NJR Midstream serves customers from local distributors and producers to electric generators and wholesale marketers through its equity ownership in a natural gas storage facility and a transportation pipeline, both of which are Federal Energy Regulatory Commission, or FERC-regulated investments. NJR Home Services provides heating, central air conditioning, standby generators, solar and other indoor and outdoor comfort products to residential homes and businesses throughout New Jersey and serves approximately 119,000 service contract customers. NJR and its more than 900 employees are committed to helping customers save energy and money by promoting conservation and encouraging efficiency through Conserve to Preserve® and initiatives such as The SAVEGREEN Project® and The Sunlight Advantage®.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (A/Stable/A-1)[270]</th></tr>
<tr><td>Business Risk – Excellent

Our ratings on NJNG reflect the consolidated credit profile of parent New Jersey Resources Corp. (NJR; not rated), of which NJNG is the principal subsidiary. NJNG has an "excellent" business profile and a "significant" financial profile under our criteria. The business risk profile is characterized by a constructive regulatory environment, an economically diverse service area, strong access to gas supply and storage, and lack of competition. However, NJR's higher-risk, unregulated operations, which represent a portion of the cash flow at the parent level, partly offset these strengths. We view NJNG's business risk profile as "excellent", reflecting a "very low" country risk because all the company's operations are based in the U.S., and the regulated utility sector's "very low" industry risk profile. Our assessment reflects the benefit of operations under a generally constructive regulatory environment, the low-operating-risk nature of its natural gas distribution operation, and an attractive service territory with above-average growth rates. Our assessment of business risk also incorporates the impact of NJR's unregulated operations, which have significantly higher risk compared with the regulated utility operations and whose contributions account for about 10% to 15% of consolidated EBITDA. We expect the mix of regulated and unregulated businesses to be in the 10% to 15% range over the next two years.</td><td>Financial Risk – Significant

We view NJNG's consolidated financial risk profile as "significant" using our medial volatility table. We apply the medial volatility table to reflect the company's unregulated businesses. Over the near term, we expect NJNG to maintain financial ratios appropriate for the current ratings. Our baseline forecast includes FFO to debt of 17% and debt to EBITDA of 3.5x.</td></tr>
</table>

Prospectively, we expect utility growth to be fueled by investments in gas infrastructure, the bulk of which will be recovered through timely rate mechanisms. Customer conversions to gas from other fuels will also continue to contribute to growth. Over the next year, we expect that NJNG will continue to increase its total customer count by about 1.5%, largely through conversions to natural gas from other fuel sources. NJNG's strengths are partly offset by its parent company's participation in various unregulated businesses. Standard & Poor's generally views unregulated businesses as riskier than regulated operations because of greater cash flow variability. As part of its unregulated segment, NJR provides wholesale energy services related to natural gas storage, pipeline transportation, and commodity activities. Performance in this segment can be affected by volatility in commodity prices, which results in earnings volatility.	
Operating Characteristics	
Operations/State/Customers (000's)[271]	• New Jersey Natural Gas Company – NJ
Total Assets (2011-2013 Average $ millions)	$2,808[272]
% of Assets in Regulated Distribution Operations (3-yr Avg)	72%[273]
Customer Mix (2014)	Customer breakdown for 2014: 84%, residential; 5%, commercial, industrial; and other; firm transportation 11%, interruptible and incentive program customers deminimis [274]
CAPEX Spend	Total NJNG CAPEX spend 2014 - $187.9 million, 2015 estimated at $222.6, 2016 estimated at $233.7 million, 2017 estimated at $153.9 million. Total of 798.1 million from 2014-2017; total company for the same period is $1.258 billion[275]

Service Territory[276]	• Primarily suburban highlighted by 100 miles of New Jersey coastline[277]
	• Population Growth CAGR 2000-2013[278]
	  o NJ –1.2%
	    o Morris - 6.2%
	    o Monmouth - 2.3%
	    o Ocean – 14.1%
	• Per Capita Income CAGR 2009-2013[279]
	  o NJ – 2.5%
	• New customer annual growth rate – average of 1.5%/year[280]
	    o Growth supported by population increase, competitive price advantage of natural gas, new construction, natural gas conversions.[281]

Residential Retail Unbundling[282]	• Offers customer choice (POLR obligations)

	– New Jersey Natural Gas Co. ~ 3% of residential customers, 17% non-residential customers
Climate[283]	• Heating load accounts for approx. 50% of energy bill - NJ
Supply Availability and Deliverability[284]	• Natural gas is plentiful and cheap
Competition with other Fuel Sources[285]	• More than 80% of households use natural gas for heating –NJ[286] • Natural gas is installed in 95% of new home construction. • NJNG is currently not subject to competition by other gas distributors in its service territory, though its franchise is non-exclusive. • Large industrial customers proximity to pipelines as well as transportation tariff mitigate the risk of bypass.
Competitive Price Advantage	Equivalent customer cost per 100,000 BTUs[287] • NJNG natural gas - $0.92 • Fuel Oil - $2.39 • Propane - $3.95 • Electricity - $4.10
Regulatory Environment	
RRA Ranking[288]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " Average /3 - NJ
Regulatory Model[289]	Cost of Service regulatory model with incentive for natural gas supply and conservation and safety.
Test Year[290]	Partially forecast –NJ
Interim Rates[291]	Allowed on an emergency basis –NJ
Typical Rate Case Lag[292]	10 mos
Most Recent Authorized ROE /2014 Estimated Earned Return[293]	10.3%
Most Recent Authorized Equity Ratio[294]	51.2%
Gas Supply Risk Mitigation and Incentives[295]	• Purchased Gas Adjustments – trued up annually through BGSS tariff, industrial customers trued up monthly. • Gas Supply Incentive Mechanisms o Basic Gas Supply Service Incentive (1992), plan includes margin sharing [296]
Volume /Demand Risk Mitigation	• Revenue Stabilization[297] o Decoupling mechanism – CIP protects utility gross margin from affects of

	weather and conservation, subject to earnings test and BGSS savings over a 12 mo. period
Capital Cost Recovery Risk Mitigation[298]	• CWIP allowed in rate base for return - TN • Established pre-approved infrastructure replacement programs – Accelerated Infrastructure Program "AIP" earns a return of 9.75% (2008), SAVEGREEN Project (2009), Safety Acceleration and Facility Enhancement Program "SAFE" earns a return of 9.75% (2012), New Jersey Reinvestment in System Enhancement "NJ RISE" earns AFUDC (2014) NGV Advantage earns a return of 10.3 percent (2014) • Capital Trackers – AIP/SAFE, NGV Fueling Stations, NJ RISE, SAVEGREEN (Immediate Return)
Other Significant Deferral and Variance Accounts[299]	• Conservation Incentive Program "CIP" (2006)[300] • New Jersey Clean Energy Program • Environmental Remediation Costs • Post employment and other benefit costs • Deferred Superstorm Sandy costs

Northwest Natural Gas Company (NYSE: NWN)

<table>
<tr><th colspan="2">SNL Financial Company Overview[301]</th></tr>
<tr><td colspan="2">NW Natural (NYSE: NWN) is headquartered in Portland, Ore., and provides natural gas service to about 705,000 residential, commercial, and industrial customers through 14,000 miles of mains and service lines in western Oregon and southwestern Washington. It is the largest independent natural gas utility in the Pacific Northwest with $3.1 billion in total assets. NW Natural and its subsidiaries currently own and operate underground gas storage facilities with storage capacity of approximately 31 Bcf in Oregon and California.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (A+/Stable/A-1)[302]</th></tr>
<tr><td>Business Risk – Excellent

Our assessment of Northwest Natural's business risk profile is "excellent," as defined in our criteria, based on what we consider the utility's "strong" competitive position, "very low" industry risk of the regulated utility industry, and "very low" country risk of the U.S. Northwest Natural's competitive position reflects a relatively constructive relationship with the Oregon Public Utility Commission, which covers fully 90% of the customer base, has resulted in consistently supportive rate design and incentive programs that allow somewhat stable cash flows that are largely insulated from gas prices, weather, and usage rate fluctuations. In Oregon, in addition to a weather normalization clause, the company has a purchased gas adjustment (PGA) mechanism that provides for recovery of actual gas costs above those in base rates in the subsequent year. This mechanism is not as credit supportive as the PGA mechanism in Washington, which provides for more timely cost recovery of all the purchased gas costs. Northwest Natural's nonregulated cash flows come primarily from its Mist and Gill Ranch storage facilities, which have contributed between 5% and 10% of EBITDA annually. Mist, in Oregon, provides mainly storage services (60% of Mist's capacity) to various utilities' operations and contributes about 90% of the company's nonregulated cash flow. We consider the cash flow from this asset to be fairly reliable given the essential nature of the service. The investment in the Gill Ranch natural gas storage facility near Fresno, Calif. is riskier because it is outside of Oregon and in an area in which it will likely compete with several other proposed storage projects, potentially depressing rates. Currently, Gill Ranch has about 15 billion cubic feet (bcf) of total storage capacity of which about 13.5 bcf is contracted to a series of highly rated counterparties with a mix of short- and medium-term contracts. The company uses the remaining capacity for optimization activities.</td>
<td>Financial Risk – Intermediate

Based on the low volatility financial ratio benchmarks, our assessment of Northwest Natural's financial risk profile is "intermediate." The utility has recurring cash flows as a natural gas distribution utility. We believe Northwest Natural's capital spending and dividend payments will lead to slightly negative discretionary cash flow on average during the forecast period, requiring management to be vigilant about cost recovery so the company can maintain its cash flow measures. The slightly negative discretionary cash flow results in an internally generated cash flow deficit that suggests that the company will require external funding. Our forecast assumes steady economic activity in the utility's Oregon market. Our base-case forecast suggests mostly steady key credit measures for the next several years. We expect debt leverage measures to remain roughly the same as in previous years, with debt to EBITDA between 3.5x and 4x. For the 12 months ended Dec. 31, 2013, FFO to debt was about 20%, cash flow from operations (CFO) to debt was about 18.5%, and debt to EBITDA was 4x. Our baseline forecast includes FFO to debt of roughly 18% to 20% and CFO to debt that ranges from 19% to 23% over the next few years.</td></tr>
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Operating Characteristics	
Operations/State/Customers (000's)[303]	• Northwest Natural Gas Co. – OR - 625 • Northwest Natural Gas Co. – WA - 70
Total Assets (2011-2013 Average $ millions)	$2,844[304]
% of Assets in Regulated Distribution Operations (3-yr Avg)	89%[305]
Customer Mix (2014)	Rev. breakdown: residential, 59%; commercial, 29%; industrial, gas transportation, and other, 12%.[306]
CAPEX Spend	Total NWN Utility CAPEX estimated spend 2014 - $142 to $165 million (including gas reserves spending), Utility CAPEX for next 5 years (2014-2018) is estimated to be $600 to $700 million.[307]
Service Territory[308]	• Provide exclusive natural gas service to over 100 cities in Western OR and Southwest WA, including the Portland metropolitan area. • Estimated population in 3.4 million in service territory. • Includes most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portion of Washington along the Columbia River. • 90% of customers are in OR • High customer growth due to lower historical saturation of natural gas ~ 60% o Population Growth CAGR 2009-2013[309] o OR –0.8% o WA – 1.1% • Per Capita Income CAGR 2009-2013[310] o OR – 2.8% o WA – 3.2% • New customer annual growth rate – average of 1.4%/year[311] o Growth supported by new construction and natural gas conversions.[312] • Bypass risk of industrial customers is a noted concern of NWN, but competitive transportation tariffs mitigate this risk.
Residential Retail Unbundling[313]	• No retail unbundling
Climate[314]	• Space heating load accounts for approx. 31% of energy bill, water heating load is an additional 23% – OR, WA
Supply Availability and Deliverability[315]	• Supply is plentiful and relatively cheap • Has made long term investment in natural gas reserves, NWN earns rate base return on its investment in reserves.[316]

Competition with other Fuel Sources[317]	• ~ 50 of households use natural gas for primary heating fuel – OR, WA[318] • NWN is currently not subject to competition by other gas suppliers in its service territory. • Large industrial customers' proximity to pipelines provides opportunities for bypass but transportation tariff mitigates the risk of bypass.
Competitive Price Advantage[319]	Natural gas enjoys significant price advantage in all jurisdictions across all customer classes (between $^1/_3$ and ¼ of electric price)
Regulatory Environment	
RRA Ranking[320]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " Average /3 – OR Average/2 - WA
Regulatory Model[321]	Cost of Service regulatory model with incentive for natural gas supply
Test Year[322]	OR- Partially to fully forecast test period WA – Historical test period with known and measurable changes allowed
Interim Rates[323]	OR – No interim rates WA – Interim rates allowed under emergency circumstances
Typical Rate Case Lag[324]	OR - 10 mos WA – 9 mos
Most Recent Authorized ROE[325]	OR – 9.5% (2012) WA – 10.1%
Most Recent Authorized Equity Ratio[326]	OR – 50% (2012) WA – 51%

Gas Supply Risk Mitigation and Incentives[327]	• Purchased Gas Adjustments
	  o OR – trued up annually but does allow for out of cycle adjustment if gas costs change by > 10%
	  o WA – Annually – defer difference between actual gas costs and PGA to be passed on to customers in next annual PGA.
	• Gas Supply Incentive Mechanisms
	  o NWN – PGA contains a sharing mechanism for changes in gas costs subject to an earnings test
	  o NWN -OR is permitted to retain 80% of the margin received from interstate and intrastate storage service, and 33% of the margin attributable to the optimization of core customer storage and related transportation services.

Volume /Demand Risk Mitigation	• Revenue Stabilization[328]
	  o Decoupling mechanism –
	    ▪ OR – has separate mechanisms for conservation decoupling and weather normalization (WARM) but together equate to full decoupling.
	    ▪ WA - none

Capital Cost Recovery Risk Mitigation[329]	• Established pre-approved infrastructure replacement programs –System Integrity Program (SIP) - OR • Capital Trackers – OR
Other Significant Deferral and Variance Accounts[330]	• Site Remediation and Recovery Mechanism (SRRM) – OR • Pension Balancing – OR • Environmental Cost Deferral – OR, WA

Piedmont Natural Gas Co., Inc. (NYSE: PNY)

SNL Financial Company Overview[331]	
Piedmont Natural Gas is an energy services company primarily engaged in the distribution of natural gas to more than one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including customers served by municipalities who are wholesale customers. Subsidiaries include joint venture, energy-related businesses, including unregulated retail natural gas marketing, regulated interstate natural gas transportation and storage, and regulated intrastate natural gas transportation businesses.	
S&P Ratings Summary (A/Stable/A-1)[332]	
Business Risk – Excellent Our assessment of Piedmont's business risk profile as "excellent" incorporates the benefits of operations under generally constructive regulatory environments, the low-operating-risk nature of its natural gas transmission and distribution operations, and the attractive service territories that continue to demonstrate robust customer growth. The business risk profile also benefits from growth capital spending that is geared toward the regulated utility and regulated nonutility operations, increasing their contribution to well over 90% of total operating income. Our assessment of business risk also incorporates the impact of Piedmont's unregulated operations, which have significantly higher risk compared with the regulated utility operations and whose contribution we expect will decline modestly over the next few years. We have revised our assessment of Piedmont's competitive position from "strong" to "excellent", which does not affect the company's "excellent" business risk profile. The revision reflects our expectation that Piedmont's volatility of profitability will moderate in the future, benefiting from the recent base rate increases and its ability to recover infrastructure-related investments in North Carolina and Tennessee via riders. We expect that the combination of recent rate cases in North Carolina and Tennessee along with credit supportive elements in all three jurisdictions in which Piedmont operates should mitigate the need for frequent rate case filings and support the company's business risk profile. Most recently, in North Carolina and Tennessee, Piedmont has received regulatory approval to implement an integrity management rider that provides for recovery of infrastructure replacement capital spending in a timely manner. Piedmont is growing its investment in regulated nonutility operations with its 24% participation in the Constitution pipeline. This investment, which will total about $150 million over the next few years, is consistent with Piedmont's other equity investments and is supported by long-term, fee-based contracts	**Financial Risk – Significant** Under our base case scenario, we assess Piedmont's financial risk profile as being in the "intermediate" category using the low volatility financial ratio benchmarks, with FFO/debt ranging from 16% to 18% and debt/EBITDA ranging from 4x to 4.5x. We expect Piedmont's financial profile will be supported by the decoupling mechanism in North Carolina and the company's ability to recover infrastructure investments via rider mechanisms. Importantly, our base case scenario incorporates Piedmont's efforts to consistently maintain a balanced capital structure, issuing equity when necessary, and supporting our view of the company's financial policies as generally conservative.

for the project that help mitigate risk.	
Operating Characteristics	
Operations/State/Customers (000's)[333]	• Piedmont Natural Gas Co. NC - 685 • Piedmont Natural Gas Co. SC - 135 • Piedmont Natural Gas Co. TN- 168
Total Assets (2011-2013 Average $ millions)	$3,600[334]
% of Assets in Regulated Distribution Operations (3-yr Avg)	97.21%[335]
Customer Mix	2014 revenue mix: residential (46%), commercial (26%), industrial (14%), other (13%).[336] 2014 customer mix: 90%, residential; 9%, commercial; 1%, industrial and other.[337] • Have one large customer that contributes 6% of total operating revenues and 11% of total margin.[338]
CAPEX Spend	Total utility Capex and JV Contributions spend 2014 - $515 million, 2015 estimated at $605 million, 2016 estimated at $600 million, and 2017 estimated at $630 million[339]

Service Territory[340]	• Includes Major Metropolitan Areas
	  o TN (Nashville)[341]
	• Hold non-exclusive franchise agreements in many of the communities they serve which expire and must be renewed or renegotiated.[342]
	• New customers increased by 13.7% over 2014, (72% due to new home construction, 17% due to natural gas conversions, 11% addition of new commercial and industrial customers)[343]
	• Population Growth CAGR 2009-2013
	  o NC – 1%
	  o SC – 1%
	  o TN– 0.7%
	• Per Capita Income CAGR 2009-2013
	  o NC – 2.6%
	  o SC – 2.5%
	  o TN – 3.5%
	• 1.6% customer growth for 2014 and projected for 2015, primarily attributable to new home construction[344]

Residential Retail Unbundling[345]	• No customer choice –NC, SC, TN
Climate[346]	• Heating load accounts for approx. 29% of energy bill for space heating and 17% for water heating – NC, SC • Average weather 34% spent on space heating and 18% spent on water heating – TN

Supply Availability and Deliverability[347]	• Natural gas is plentiful and cheap; no delivery constraints noted • Purchases natural gas under firm transportation agreements to meet system design requirements and have up almost an equal amount in peaking capacity. Own 35.6 million MMBtu of storage capacity.[348]
Competition with other Fuel Sources[349]	• Natural gas is used ~ 33% of time for heating –TN (electricity is used roughly 2/3 of time) • Natural gas is used ~ 25% of time for heating – NC, SC (greatest competition is electricity, but other heating sources are used in ~12% of households)
Competitive Price Advantage[350]	• Natural gas enjoys significant price advantage in all jurisdictions across all customer classes (between 1/3 and ¼ of electric price) • Compete with pipelines to serve natural gas generation customers[351]
Regulatory Environment	
RRA Ranking[352]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " • NC - Average/1 • SC - Average/1 • TN - Average/1
Regulatory Model[353]	Cost of Service – SC Formula Rate Plan (annual rate mechanism) – TN, NC Earnings sharing mechanism – SC (rates outside of 50 bps deadband of authorized ROE are adjusted)[354]
Test Year[355]	Forecast – TN Historical (known and measurable changes) – SC, NC
Interim Rates[356]	Allowed on an emergency basis – NC, SC, TN
Typical Rate Case Lag[357]	• NC – 6 mos. • SC – 6 mos. • TN - 4 mos.
Most Recent Authorized ROE[358]	• NC – 10.0% (1/1/14) • SC – 10.2% (1/1/14) • TN - 10.2% (3/1/12)
Most Recent Authorized Equity Ratio[359]	• NC – 50.7% (1/1/14) • SC – 55.0% (1/1/14) • TN - 52.7% (3/1/12)

Gas Supply Risk Mitigation and Incentives	• Purchased Gas Adjustments o Annually – (subject to prudence review)NC, SC, and in the case of TN (subject to Tennessee Incentive Plan "TIP" which replaces prudence reviews)[360] • Gas Supply Incentive Mechanisms o TN[361] • Gas Supply Margin Sharing o NC, SC, TN[362]
Volume /Demand Risk Mitigation	• Revenue Stabilization[363] o 72% of 2014 gas utility margin is fixed by NC Decoupling, NC/TN Integrity Management Riders (38%), Facilities Charges (21%), Fixed Rate Contracts (13%) o 16% of 2014 gas utility margin is semi-fixed by SC – RSA & WNA (7%), and TN WNA (9%) o 12% of 2014 gas utility margin subject to volumetric risk
Capital Cost Recovery Risk Mitigation	• AFUDC allowed for both debt and equity – NC[364] • The PSC allows a cash return on CWIP – SC, TN[365] • Established pre-approved infrastructure replacement programs – Integrity Management Rider (IMR), TN, NC[366] • Capital Trackers – TN, NC[367]
Other Significant Deferral and Variance Accounts[368]	• Uncollectible Gas Cost Recovery – NC, SC, TN[369] • Environmental cost deferral – SC[370] • Deferral for flooding in Nashville - TN[371] • Rider for lost margin due to system bypass by large industrial customers

South Jersey Industries, Inc. (NYSE: SJI)

SNL Financial Company Overview[372]

South Jersey Industries (NYSE: SJI), an energy services holding company based in Folsom, NJ, operates its business through two primary subsidiaries. South Jersey Gas, one of the nation's fastest growing natural gas utilities, delivers clean, efficient natural gas and promotes energy efficiency to approximately 365,000 customers in southern New Jersey. SJI's non-regulated businesses, under South Jersey Energy Solutions, promote efficiency, clean technology and renewable energy by developing, owning and operating on-site energy production facilities- including Combined Heat and Power, Solar, and District Heating and Cooling projects; acquiring and marketing natural gas and electricity for retail customers; providing wholesale commodity marketing and risk management services; and offering HVAC and other energy-efficiency related services.

S&P Ratings Summary (BBB+/Stable/--)[373]

Business Risk – Excellent

Standard & Poor's ratings on South Jersey Industries Inc. reflect the consolidated credit profile of its regulated natural gas utility, South Jersey Gas Co. (SJG), which accounts for about 85% of consolidated cash flows and its higher risk unregulated subsidiaries that provide retail energy marketing, wholesale energy services, and energy-related project development. SJG serves roughly 362,000 natural gas customers in southern New Jersey. We view SJI's business risk profile as "excellent", reflecting a "very low" country risk because all the company's operations are based in the U.S., and the regulated utility sector's "very low" industry risk profile. Our assessment reflects the benefit of operations under a generally constructive regulatory environment, the low-operating-risk nature of its natural gas distribution operation, and an attractive service territory with above-average growth rates. Our assessment of business risk also incorporates the impact of SJI's unregulated operations, which have significantly higher risk compared with the regulated utility operations and whose contributions account for about 15% of consolidated EBITDA. We expect the mix of regulated and unregulated businesses to be in the 15% range over the next two years. Prospectively, we expect utility growth to be fueled by investments in gas infrastructure, the bulk of which will be recovered through timely rate mechanisms. Customer conversions to gas from other fuels will also continue to contribute to growth. Over the next year, we expect that SJG will continue to increase its total customer count by about 1.5%, largely through conversions to natural gas from other fuel sources. SJI's strengths are partly offset by its participation in various unregulated businesses. Standard & Poor's generally views unregulated businesses as riskier than regulated operations because of greater cash flow

Financial Risk – Significant

We view SJI's financial risk profile as "significant" using our medial volatility table. We apply the medial volatility table to reflect the company's unregulated businesses. Over the near term, we expect SJI to maintain financial ratios appropriate for the current ratings. However, incremental investments in large energy facilities could result in a weaker business profile, which would likely require a stronger sustained consolidated financial performance to maintain the same ratings. As of Dec. 31, 2013, SJI's total debt, including capitalized operating leases and tax-effected pension and postretirement obligations, was about $1 billion, resulting in adjusted FFO to total debt of about 11% for SJI.

variability. As part of its unregulated segment, SJI provides wholesale energy services related to natural gas storage, pipeline transportation, and commodity activities. Performance in this segment can be affected by volatility in commodity prices, which results in earnings volatility. We expect that the unregulated businesses will represent about 30% to 40% of SJI's total capital spending for 2014. We also expect a majority of the earnings for the unregulated retail segment to come from Marina Energy, an energy project development business. We view the gas-fired cogeneration, thermal landfill, and solar projects as having somewhat less risk than the energy marketing segment because of their long-term contracts and the essential services they provide. Income tax credits associated with a number of renewable projects also contributed to earnings.	
Operating Characteristics	
Operations/State/Customers (000's)[374]	• South Jersey Gas Co. – NJ – 364 (93% residential, 7% commercial and industrial)
Total Assets (2011-2013 Average $ millions)	$1,770[375]
% of Assets in Regulated Distribution Operations (3-yr Avg)	68%[376]
Customer Mix (2014)[377]	Gas sales, transportation and capacity release for 2014 amounted to 138.2 MMdts (million dekatherms), of which 65.2 MMdts were firm sales and transportation, 1.4 MMdts were interruptible sales and transportation and 71.6 MMdts were off-system sales and capacity release. The breakdown of firm sales and transportation includes 42.6% residential, 19.4% commercial, 20.6% industrial, and 17.4% cogeneration and electric generation.
CAPEX Spend	Total SJI Utility projected CAPEX spend 2015 estimated at $211.2 million, 2016 estimated at $228.5 million, 2017 estimated at $157.3 million.[378]
Service Territory	• Serves 7 southern-most counties in New Jersey, including the Atlantic City metropolitan area through non-exclusive franchise agreements.[379] • There are no other gas utilities operating in SJG's service territory. • Population Growth CAGR 2009-2013 – 0.4%[380] • Per Capita Income CAGR 2009-2013 – 2.5%[381] • New customer annual growth rate – average of 1.4% in 2013[382] o Growth supported primarily by natural gas conversions (69%).[383] • Projecting average annual customer growth

	of 2%/year[384] • Approx. 70% of market share[385] • Approx. 10% anticipated market penetration for CNG[386]
Residential Retail Unbundling[387]	• Offers customer choice (POLR obligations) – SJI. ~ 8% of residential customers, 15% non-residential customers
Climate[388]	• Space heating accounts for approx. 49% and water heating accounts for approx. 18% of energy bill
Supply Availability and Deliverability[389]	• Natural gas is plentiful and cheap – NJ is in close proximity to the Marcellus Shale Region
Competition with other Fuel Sources	• More than 80% of households use natural gas for heating –NJ[390]
Competitive Price Advantage[391]	• Natural gas enjoys significant price advantage in all jurisdictions across all customer classes (between $^1/_3$ and ¼ of electric price)
Regulatory Environment	
RRA Ranking[392]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " Average /3 - NJ
Regulatory Model[393]	Cost of Service regulatory model
Test Year[394]	Partially forecast –NJ
Interim Rates[395]	Allowed on an emergency basis –NJ
Typical Rate Case Lag[396]	10 mos
Most Recent Authorized ROE	9.75%[397]
Most Recent Authorized Equity Ratio	51.9%[398]
Gas Supply Risk Mitigation and Incentives	• Purchased Gas Adjustments – trued up annually through BGSS tariff, industrial customers trued up monthly.[399] • SJG may retain 100% of the first $7.8 million of margins associated with off-system sales, interruptible sales, and interruptible transportation activities. Margins beyond this level are allocated such that 85% flows to ratepayers and 15% is retained by the company.[400]
Volume /Demand Risk Mitigation	• Revenue Stabilization[401] o Decoupling mechanism – CIP protects utility gross margin from affects of weather and conservation, subject to earnings test and BGSS savings over a

	12 mo. period
Capital Cost Recovery Risk Mitigation[402]	• AFUDC with equity and debt allowed on CWIP. • Established pre-approved infrastructure replacement programs – Accelerated Infrastructure Program "AIP" or "CIRT" earns immediate return, Storm Hardening Infrastructure Program "SHARP" earns immediate return, Energy Efficiency Program. • Capital Trackers – AIP, Storm Hardening Infrastructure Tracker, Energy Efficiency Tracker (EET)
Other Significant Deferral and Variance Accounts[403]	• Pension and Post Retirement Benefits • Interest Rate Contracts • Social Benefits Clause • Remediation Adjustment Clause • New Jersey Clean Energy Program • Universal Service Fund • Pipeline Integrity Management regulations • Superstorm Sandy

Southwest Gas Corporation (NYSE: SWX)

SNL Financial Company Overview[404]	
Southwest Gas Corporation is principally engaged in the business of purchasing, distributing and transporting natural gas to residential, commercial and industrial customers in the southwestern United States. Southwest has approximately 2,200 employees who serve approximately 1.9 million customers in Arizona, Nevada and portions of California. The company added 28,000 customers in 2013.	
S&P Ratings Summary (A-/Stable/--)[405]	
Business Risk – Excellent We view SWG's business risk profile as "excellent", reflecting its mostly lower-risk regulated gas utility business. Based on our assessment of the company using forward-looking revenues, assets, earnings, EBITDA, and rate base, we view the company as consisting of about 38% regulated by the Arizona Corporation Commission, 34% regulated by the Public Utilities Commission of Nevada, 17% nonregulated NPL, 8% regulated by the California Public Utilities Commission, and 3% regulated by the Federal Energy Regulatory Commission. We view the company as having geographic and regulatory diversity because its regulated gas businesses serve about 1.9 million customers in Arizona, Nevada, and California. We view the regulatory jurisdictions of Arizona, Nevada, and California as strong/adequate" (see "Utility Regulatory Assessments For U.S. Investor-Owned Utilities," Jan. 7, 2014). In addition, we view the company's management of regulatory risk as average compared with peers. This reflects the company's ability to generally earn its allowed return on equity through more recent credit supportive rate case orders and various riders that include purchased-gas, accelerated pipe replacement, infrastructure programs, customer-owned yard line, and decoupling. Currently, the company has filed a rate case in California requesting a rate increase of about $11.6 million and the administrative law judge recommended an increase of $7.5 million. We expect a rate order by June 2014. We view the company's higher risk nonregulated business, NPL, as consisting of about 17% of the total company. NPL is primarily involved with pipe-replacement work for other regulated utilities operating under multiyear contracts. We expect that because of the growth of the regulated utility, NPL will continue to account for about 17% of the consolidated company.	**Financial Risk – Significant** For SWG, we use the medial volatility table, reflecting the company's lower-risk regulated gas business and its higher-risk NPL business. We consider the company's financial risk profile to be "intermediate", reflecting our expectation that the company's financial measures will only marginally drop over the next two years despite the high capital spending program. We expect that the company will continue to benefit from higher-than-average customer growth and the use of its riders that will offset the immediate need for filing for a larger rate increases. Specifically, we expect that FFO to debt will be consistently greater than 25% and debt to EBITDA of less than 3.2x.
Operating Characteristics	
Operations/State/Customers (000's)[406]	1,930 million customers • Southwest Gas Corp. – AZ – 1,033 • Southwest Gas Corp. – NV - 708 • Southwest Gas Corp. – CA - 189

	During 2014, 55% of operating margin was earned in Arizona, 34% in Nevada, and 11% in California.
Total Assets (2011-2013 Average $ millions)	$4,443[407]
% of Assets in Regulated Distribution Operations (3-yr Avg)	94%[408]
Customer Mix (2014)[409]	Southwest earned 85% of its operating margin from residential and small commercial customers, 4% from other sales customers, and 11% from transportation customers.
CAPEX Spend[410]	• 5.2% Gas Utility Plant CAGR for all utility jurisdictions from 2012-2014. • Natural Gas Operations CAPEX spend 2013 at $315 million, 2014 at $350 million, 2015 estimated at $445 million. 2015-2017 estimated at $1.3 billion. • $23 million of $445 million (2015 estimate) is covered by trackers ~ 5%.

Service Territory	• Service areas in Arizona include most of the central and southern areas of the state including Phoenix, Tucson, Yuma, and surrounding communities. Service areas in northern Nevada include Carson City, Yerington, Fallon, Lovelock, Winnemucca, and Elko. Service areas in southern Nevada include the Las Vegas valley (including Henderson and Boulder City) and Laughlin. Service areas in southern California include Barstow, Big Bear, Needles, and Victorville. Service areas in northern California include the Lake Tahoe area and Truckee. [411]
	• Population Growth CAGR 2009-2013[412]
	  o CA - 0.9%
	  o NV – 1.0%
	  o AZ – 1.1%
	• Per Capita Income CAGR 2009-2013[413]
	  o CA - 3.9%
	  o NV – 1.6%
	  o AZ – 2.1%
	• Southwest completed 20,000 first-time meter sets, but realized 26,000 net new customers during 2014, an increase of 1.4%. The incremental additions reflect a return to service of customer meters on previously vacant homes. Southwest projects customer growth of about 1.5% for 2015.[414]
	• Service territories are typically above the national average for unemployment, though AZ is typically very close to national average, NV substantially above[415]
	• Employment growth[416]
	  o SoCal - 2%

	o NV – 2.3% o AZ – 2.6%
Residential Retail Unbundling[417]	• Offers customer choice for core customers (i.e. > 120,000 therms/year – CA < 1% of customers have participated • No retail unbundling – AZ, NV
Climate[418]	• AZ – Climate is warmer than national average - space heating accounts for approx. 15% and water heating accounts for approx. 17% of energy bill • NV – space heating accounts for approximately 25% of energy bill and water heating 18% • CA - space heating accounts for approximately 27% of energy bill and water heating 25%
Supply Availability and Deliverability[419]	Natural gas supplies for Southwest's southern system (Arizona, southern Nevada, and southern California properties) are primarily obtained from producing regions in Colorado and New Mexico (San Juan basin), Texas (Permian basin), and Rocky Mountain areas. For its northern system (northern Nevada and northern California properties), Southwest primarily obtains natural gas from Rocky Mountain producing areas and from Canada. Forecasts show that an ample and diverse natural gas supply is available to Southwest's customers at a highly competitive price when compared with competing forms of energy.
Competition with other Fuel Sources[420]	• Southwest competes with electricity for space heating, water heating and cooking • AZ - 30% of households use natural gas for heating, 58% use electricity • NV - 50% of households use natural gas for heating, 40% use electricity • CA – 59% use natural gas for heating, 14% of homes not heated due to mild climate, remainder ~21% are heated with electricity.
Competitive Price Advantage[421]	• Southwest competes with interstate transmission pipeline companies, such as El Paso, Kern River, Transwestern and Tuscarora, to provide service to certain large end-users. End-use customers located in proximity to these interstate pipelines pose a potential bypass threat. Southwest has remained competitive through the use of negotiated transportation contract rates, special long-term contracts with electric generation and cogeneration customers, and other tariff programs. [422] • Natural gas enjoys significant price

	advantage in all jurisdictions across all customer classes (between 1/3 and ¼ of electric price)
Regulatory Environment	
RRA Ranking[423]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " Average /3 – AZ Average /1 – CA Average /2 - NV
Regulatory and Legislated Initiatives	Subject to California Air Resources Board (CARB) requires compliance with GHG Emissions Reporting Program and CA Cap and Trade Program – Program costs are expected to receive regulatory treatment and should not impact earnings.[424]
Regulatory Model[425]	Cost of Service regulatory model
Test Year[426]	• Historical with known and measurable changes – AZ, NJ • Forecast test year – CA
Interim Rates[427]	Allowed on an emergency basis –CA Routinely allowed – AZ Not allowed - NV
Typical Rate Case Lag[428]	AZ – 13 mos. NV – 7 mos. CA – 17 mos.
Most Recent Authorized ROE[429]	AZ - 9.50% (2012) Northern NV – 9.3% (2013) Southern NV - 10% (2013) CA- 10.10% (2014)[430] Company return on average common equity for 2014 was 9.7% for 2014 and 10.6% for 2013 for the total company; gas operations earned returns were 8.5% for 2014 and 9.6% for 2013[431]
Most Recent Authorized Equity Ratio[432]	AZ – 52.3% (2012) Northern NV – 59.1% (2013) Southern NV - 42.7% (2013) CA – 55% (2014)
Gas Supply Risk Mitigation and Incentives[433]	Purchased Gas Adjustment Clauses: • Monthly PGA – AZ, CA (based on projected pricing) • Quarterly PGA - NV
Volume /Demand Risk Mitigation	• Revenue Stabilization[434] o Decoupling mechanism – AZ, NV, CA
Capital Cost Recovery Risk Mitigation[435]	• AFUDC with equity and debt allowed on CWIP - AZ.

	• Established pre-approved infrastructure replacement programs – EVPP – NV, COYL and IRRAM in CA, New LNG facility – AZ, COYL in AZ (leak survey and replacement program) • Capital Trackers – Infrastructure Replacement Program "EVPP" – NV, COYL in AZ
Other Significant Deferral and Variance Accounts[436]	• GIR Surcharge Mechanism for Deferral Account Recovery - NV • Post Test Year Rate Mechanism Providing for Annual Attrition increases – CA • GHG Allowance Trading Balancing Accounts - CA

WGL Holdings Inc. (NYSE: WGL)

<table>
<tr><th colspan="2">SNL Financial Company Overview[437]</th></tr>
<tr><td colspan="2">Headquartered in Washington, D.C., WGL is a leading source for clean, efficient and diverse energy solutions. With activities in 32 states and the District of Columbia, our operating units consist of Washington Gas, WGL Energy, WGL Midstream and Hampshire Gas. WGL Energy is an operating unit that delivers a full ecosystem of energy offerings including natural gas, electricity, green power, carbon reduction, distributed generation and energy efficiency provided by WGL Energy Services, Inc. (formerly Washington Gas Energy Services, Inc.) and WGL Energy Systems, Inc. (formerly Washington Gas Energy Systems, Inc.). WGL provides options for natural gas, electricity, green power and energy services, including generation, storage, transportation, distribution, supply and efficiency.</td></tr>
<tr><th colspan="2">S&P Ratings Summary (A+/Stable/A-1)[438]</th></tr>
<tr><td>Business Risk – Excellent
Standard & Poor's ratings on Washington, D.C.-based WGL reflect the consolidated credit profile of the company's regulated and unregulated operating units. These units include Washington Gas Light Co., a regulated natural gas distribution utility that delivers to 1.1 million customers in the District of Columbia, Maryland, and Virginia; Washington Gas Energy Services Inc. (WGE Services; not rated), an unregulated retail gas and power marketer; Washington Gas Energy Systems Inc. (not rated), which provides design-build energy-efficient and sustainable solutions to government and commercial clients; and WGL Midstream, which develops, acquires, manages, and optimizes natural gas storage and transportation assets. We view WGL's business risk profile as "excellent", reflecting a "very low" country risk because the company operates in the U.S., along with the regulated utility sector's "very low" industry risk profile. Our assessment reflects Washington Gas Light's affluent and stable service territory, supportive regulatory mechanisms, moderate regulatory and market diversification, and low operating risk. Supportive regulatory mechanisms enhance Washington Gas Light's cash flow stability, which further supports credit quality. Adequate allowed returns on equity (ROE) and a number of recovery mechanisms, including decoupling, purchase gas adjustment mechanisms, weather normalization clauses, and bad debt recovery all support cost recovery and stable revenues. Washington Gas Light also benefits from a revenue-normalization mechanism in Maryland, weather-normalization and conservation mechanisms in Virginia (which accounts for more than 80% of delivered natural gas volumes), and a gas administrative charge in all three jurisdictions. Allowed ROEs have been near 10% in all three jurisdictions. Our assessment of business risk also incorporates the effect of WGL's unregulated operations, which have significantly higher risk</td><td>Financial Risk – Intermediate
We view WGL's financial risk profile as “intermediate" using our medial volatility table. We apply the medial table to reflect the company's unregulated businesses. Over the near term, we expect WGL to maintain financial ratios appropriate for the current ratings. The unregulated operations produce somewhat volatile cash flows, but cash flows from Washington Gas Light should remain stable, supported by recent rate orders and tracking mechanisms. We expect WGL to report FFO to total debt of 25% or slightly higher over the next few years.</td></tr>
</table>

compared with the regulated utility operations and whose contributions account for slightly less than 15% of consolidated EBITDA. We expect WGL's unregulated operations to remain at about 15% of consolidated EBITDA in the next two years. The unregulated businesses are credit-dilutive at WGL's high rating level because their cash flow is subject to more volatility and they lack the benefits of regulation. We expect utility growth to be fueled by investments in gas infrastructure, most of which will be recovered through timely rate mechanisms. Customer conversions to gas from other fuels will also continue to contribute to growth. WGE Services operates in a highly competitive industry that has minimal barriers to entry, low margins, and volatile cash flows. We expect volumes, commodity prices, and competitor pricing to propel the gas and electric businesses. WGL also has a growing solar business that consists of a fleet of solar projects located in its energy sales territories and sells electric power to its customers. We believe this business is utility-like in nature due to its long-term income stream and consider it to be generally low-to-moderate risk. However, new projects bear the risk that changes in legislation will reduce or eliminate tax credits and incentives. We expect continued growth in the midstream business, as seen with the recent investments in Constitution Pipeline Co. and the Central Penn Line.	
Operating Characteristics	
Operations/State/Customers (000's)[439]	• Washington Gas – D.C. – 156 • Washington Gas – MD. – 454 • Washington Gas – VA – 507
Total Assets (2011-2013 Average $ millions)[440]	$4,060
% of Assets in Regulated Operations (3-yr Avg)[441]	85%
Customer Mix (2013 Operating Revenue)[442]	Residential –62% Commercial and Industrial – 15% Transportation – 19% Other –4%
CAPEX Spend	Total Projected Utility Capex spend (all utilities): 2015 - $303.1 million, 2016 - $372.8 million, 2017- $355.4 million, 2018 - $359.5 million, 2019 - $360.0 million, for a total of $1.751 billion over next 5 years. Total Capex for the Company will be approximately $2.757 billion over next 5 years[443]
Service Territory[444]	• Utility meter growth 1.6% • Greater Washington DC is the fourth largest regional economy in the U.S. and continues to grow. It is estimated that 60,000 payroll

	jobs will be added annually to the Washington economy from 2014-2018.
	• Compared to other major metropolitan areas, Washington D.C. has:
	  o Highest median household income
	  o Lowest unemployment rate
	  o Low uncollectible rates
	  o Highly educated workforce
	• Washington gas captures over 90% of new single family homes.
	• New tariffs with lower customer contributions are driving higher conversion rate.
	• Pursuing opportunities to increase penetration in multi-family market – D.C. is 3rd largest apartment market and 5th larges condo market in the country.
	  o New tariff in MD provides financial incentives for developers

Residential Retail Unbundling[445]	Customer choice programs for natural gas customers were available to all of Washington Gas' regulated utility customers in the District of Columbia, Maryland and Virginia. Of Washington Gas' 1.1 million active customers at September 30, 2014, approximately 182,000 (~16%) customers purchased their natural gas commodity from unregulated third party marketers.
Climate[446]	• Average weather 25%-35% spent on space heating, and 17% - 18% spent on water heating – DC, VA, MD
Supply Availability and Deliverability[447]	• Natural gas is plentiful and cheap. WGL service territory is in close proximity to natural gas production basins
Competition with other Fuel Sources[448]	• Natural gas is used ~25% to 35% of time for heating –MD, VA, DC • Most significant product competition occurs between natural gas and electricity.[449] • Washington Gas continues to attract the majority of the new residential construction market in its service territory, and consumers' continuing preference for natural gas allows Washington Gas to maintain a strong market presence.[450] • In the interruptible market, fuel oil is the prevalent energy alternative to natural gas. Washington Gas' success in this market depends largely on the relationship between natural gas and oil prices.[451]
Competitive Price Advantage[452]	• Because of the high fixed costs and significant safety and environmental

	considerations associated with building and operating a distribution system, Washington Gas expects to continue being the only owner and operator of a distribution system in its current franchise area for the foreseeable future. • The nature of Washington Gas' customer base and the distance of most customers from interstate pipelines mitigate the threat of bypass of its facilities by other potential delivery service providers. • Washington Gas generally maintains a price advantage over competitive electricity supply in its service area for traditional residential uses of energy such as heating, water heating and cooking.
Regulatory Environment	
RRA Ranking[453]	Rankings are Above Average, Average and Below Average, 1 indicates stronger rating "+" and 3 indicates weaker rating "- " Above Average /2 – VA Average /3 - DC Below Average /2 - MD
Regulatory Model	Cost of Service in all states, Earnings are shared with customers on a 60/40 basis[454] Incentives for meeting demand reduction targets - VA
Test Year[455]	Combination of average historic test year with some items forecast – DC Historical (known and measurable changes) – VA, MD
Interim Rates[456]	Routinely allowed - VA Interim rates are allowed but rarely requested by the utilities –MD Interim rates are generally not requested – DC
Last Rate Case Lag[457]	DC – 14 mos MD – 7 mos VA – 17 mos
Most Recent Authorized ROE /2014 Estimated Earned Return	• Washington Gas – MD 9.50% (2013) was appealed and affirmed.[458] • Washington Gas – DC 9.25% (2013)[459] • Washington Gas – VA 9.75% (2012)[460]
Most Recent Authorized Equity Ratio	• Washington Gas – MD 53.02% (2013)[461] • Washington Gas – DC 59.3% (2013[462] • Washington Gas – VA 59.63% (2012)[463]
Gas Supply Risk Mitigation and Incentives[464]	• Purchased Gas Adjustments o Quarterly adjustment - VA

	o Annual – MD o Quarterly forecast for annual adjustment mechanism – DC o Adjustment charge for uncollectible gas commodity costs may be run through the PGA – DC, MD, VA o WG may recover carrying costs on storage inventory – DC, MD, VA o All hedging costs are run through the PGA- DC • Gas Supply Margin Sharing o MD • Asset management revenue sharing mechanism - VA
Volume /Demand Risk Mitigation[465]	• Revenue Stabilization o Decoupling (Revenue Normalization Adjustment Mechanism) – VA, MD • Weather Normalization – D.C. (pending), VA[466]
Capital Cost Recovery Risk Mitigation[467]	• Recovery of return on CWIP o AFUDC – (prescribed by formula) DC, MD, VA. The before tax rates were: 3.65% and 5.43% for 2014 and 2013, respectively.[468] o CWIP in rate base allowed for facilities to be commercially operable within 1 year beyond the test year or for infrastructure investment that is recovered through riders - VA • Established pre-approved infrastructure replacement programs – D.C. – Accelerated Pipe Replacement Plan; VA (SAVE), MD (STRIDE) • Capital Trackers – DC, MD, VA
Other Significant Deferral and Variance Accounts[469]	• Regulatory asset to recover costs due to change in tax treatment of Med D. - DC[470] • Pension and Benefits Deferred Tracker – D.C.[471] • Energy Efficiency – MD, VA • Bad Debt Expense – DC, VA, MD

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Transportation Information System (depicting directional flow of natural gas), literature search for pipeline constraint information
390 EIA, All data from EIA's 2009 Residential Energy Consumption Survey, state fact sheets
391 EIA, Energy Prices by Sector and Source (2012 dollars per MMBtu) 2012-2040
392 SNL Financial
393 SNL Financial and New Jersey Resources 10-K (2014)
394 SNL Financial
395 SNL Financial
396 SNL Financial
397 SJI 10-K 2014 at 22.
398 SNL Financial
399 SJI 10-K 2014 at 70.
400 SNL Financial
401 SJI 10-K 2014 at 22-23.
402 SJI Investor Presentation, West Coast Investor Meetings (Sept 29 – October 1, 2014) at 9-10 and 2014 10-K at 22, 72.
403 SNL Financial and SJI 10-K (2014) at 72 - 75
404 SNL Financial
405 S&P Ratings Direct, Summary Southwest Gas Corp. (April 22, 2014)
406 SWX 2014 10-K at MD&A p. 10.
407 SWX 10-K (2013)
408 SWX 10-K (2013)
409 SWX 2014 10-K at MD&A p. 10.
410 Southwest Gas Corp. Investor Presentation, 2014 Year End Earnings Conference Call (February 26, 2015) at 28-29.
411 Southwest Gas Corp. 10-K (2014) at 12.
412 U.S. Bureau of Economic Analysis, Compound annual growth rate between any two periods, by state, "Population (persons)" and "Per capital personal income (dollars)"
413 U.S. Bureau of Economic Analysis, Compound annual growth rate between any two periods, by state, "Population (persons)" and "Per capital personal income (dollars)"
414 Southwest Gas Corp. 10-K (2014) at MD&A p. 12.
415 Southwest Gas Corp. Investor Presentation, 2014 Year End Earnings Conference Call (February 26, 2015) at 26.
416 Southwest Gas Corp. Investor Presentation, 2014 Year End Earnings Conference Call (February 26, 2015) at 27.
417 http://www.eia.gov/oil_gas/natural_gas/restructure/restructure.html
418 EIA, All data from EIA's 2009 Residential Energy Consumption Survey, state fact sheets
419 Southwest Gas Corp. 10-K (2014) at 5.
420 EIA, All data from EIA's 2009 Residential Energy Consumption Survey, state fact sheets
421 EIA, Energy Prices by Sector and Source (2012 dollars per MMBtu) 2012-2040
422 Southwest Gas Corp. 10-K (2014) at 5.
423 SNL Financial
424 Southwest Gas Corp. 10-K (2014) at 6.
425 Southwest Gas Corp. 10-K (2014) at 2.
426 Southwest Gas Corp. 10-K (2014) at 2.
427 SNL Financial
428 SNL Financial
429 SWX 10-K 2014 MD&A at 18-19.
430 Southwest Gas Corp. Investor Presentation, 2014 Year End Earnings Conference Call (February 26, 2015) at 41.
431 Southwest Gas Corp. Investor Presentation, 2014 Year End Earnings Conference Call (February 26, 2015) at 49.
432 SWX 10-K 2014 MD&A at 18-19.
433 SWX 10-K 2014 MD&A at 22.

434 Southwest Gas Corp. 10-K (2014) at 2-3.
435 Southwest Gas Corp. 10-K (2014) MD&A at 18-20.
436 Southwest Gas Corp. 10-K (2014) MD&A at 18.
437 SNL Financial
438 S&P Ratings Direct, Summary WGL Holdings Inc. (April 24, 2014)
439 WGL Resources 10-K (2014) at 6.
440 WGL Resources 10-K (2013)
441 WGL Resources 10-K (2013)
442 Calculated based on WGL 2013 Gas LDC Filing (FERC Form 2) at 300.
443 WGL Holdings Inc. Investor Presentation, *Fourth Quarter Fiscal Year 2014 Earnings Presentation* (November 13, 2014) at 13.
444 WGL Holdings Presentation, 2014 Analyst Meeting (March 13, 2014) at 24, 62.
445 WGL Resources 10-K (2014) at 9.
446 EIA, All data from EIA's 2009 Residential Energy Consumption Survey, state fact sheets
447 EIA (North American shale plays), based on data from various published studies (May 2011) (depicting major natural gas basins in North America). and EIA, Office of Oil and Gas, Natural Gas Division, Gas Transportation Information System (depicting directional flow of natural gas), literature search for pipeline constraint information
448 EIA, All data from EIA's 2009 Residential Energy Consumption Survey, state fact sheets
449 WGL Resources 10-K (2014) at 10.
450 WGL Resources 10-K (2014) at 10.
451 WGL Resources 10-K (2014) at 10.
452 WGL Resources 10-K (2014) at 10.
453 SNL Financial
454 WGL Holdings Presentation, 2014 Analyst Meeting (March 13, 2014) at 70.
455 SNL Financial
456 SNL Financial
457 SNL Financial
458 WGL Holdings 2014 10-K at 67.
459 SNL Financial.
460 SNL Financial.
461 SNL Financial.
462 WGL 2013 Gas LDC Filing (FERC Form 2).
463 SNL Financial.
464 SNL Financial
465 SNL Financial
466 WGL Holdings 2014 10-K at 67.
467 WGL Holdings 10-K (2014) at 67.
468 WGL Holdings 10-K (2014) at 84.
469 SNL Financial
470 WGL 2013 Gas LDC Filing (FERC Form 2)
471 WGL 2013 Gas LDC Filing (FERC Form 2)

James M. Coyne
Senior Vice President

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

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)
- Hydro Quebec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)

- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)
- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)

- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)

- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Areas of Expertise

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

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

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

- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

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

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

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

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

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

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

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

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

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

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maine Public Utility Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation / Eminent Domain
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro-Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro-Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-1212	Return on Equity (Gas & Electric)

Proxy Group Screening Data

Utility	Credit Rating Moody's [1]	Credit Rating S&P [1]	% Regulated Operating Income to Total Operating Income [2]	% Gas Distribution Operating Income to Total Regulated Operating Income [2]	% Gas Distribution Revenues to Total Revenues [2]	% Gas Distribution Assets [2]	Merger/ Significant Acquisition Announcement in last six months	Selected for U.S. Proxy Group?
AGL Resources Inc.	Baa1	BBB+	74%	100%	79%	81%	[8]	No
Atmos Energy Corporation	A2	A-	95%	70%	62%	98%	None	Yes
Laclede Group, Inc. (The)	Baa2	A-	94%	100%	81%	93%	[3]	No
New Jersey Resources Corporation	Aa2	A	85%	100%	25%	70%	None	Yes
NiSource Inc.	Ba1	BBB+	102%	39%	54%	37%	None	No
Northwest Natural Gas Company	A3	A+	100%	93%	96%	90%	None	Yes
Piedmont Natural Gas Company, Inc.	A2	A	100%	100%	100%	97%	None	Yes
South Jersey Industries, Inc.	A2	BBB+	111%	100%	59%	66%	None	Yes
Southwest Gas Corporation	A3	BBB+	87%	100%	67%	92%	None	Yes
UGI Corporation	A2	A	26%	100%	12%	21%	[4]	No
WGL Holdings, Inc.	A3	A+	89%	100%	49%	83%	None	Yes
U.S. Average			**88%**	**91%**	**62%**	**75%**		
U.S. Proxy Group Average			**95%**	**95%**	**65%**	**85%**		

Utility	[5]		% Regulated Operating Income to Total Operating Income [6]	% Gas Distribution Operating Income to Total Regulated Operating Income [6]	% Gas Distribution Revenues to Total Revenues [6]	% Gas Distribution Assets [6]	Merger Announcement in last six months	Selected for Canadian Proxy Group?
Canadian Utilities Ltd.	N/A	A	58%	26%	24%	19%	None	Yes
Emera, Inc.	N/A	BBB+	86%	0%	0%	0%	[9]	Yes
Enbridge Inc.	Baa2	BBB+	55%	19%	9%	14%	None	Yes
Fortis Inc.	N/A	A-	93%	38%	38%	36%	[7]	Yes
TransCanada Corporation	Baa1	A-	77%	0%	0%	0%	None	No
Valener Inc.	N/A	A-	101%	72%	69%	45%	None	Yes
Canadian Average			**78%**	**26%**	**23%**	**19%**		
Canadian Proxy Group Average			**79%**	**31%**	**28%**	**23%**		

Notes:

Proxy Group Parameters: i) Have credit ratings of at least BBB+ from S&P, or Baa1 from Moody's; ii) Pay quarterly cash dividends; iii) Have earnings growth rates from at least two utility industry analysts; iv) Averaged at least 70 percent of their operating income from regulated operations for the period 2012-2014; v) Averaged at least 70 percent of regulated operating income from natural gas distribution service in the period from 2012-2014; and was not involved in a merger or significant transformative transaction during the evaluation period.

[1] Data derived from Bloomberg, SNL Financial, Standard & Poor's, and Moody's as of August 31, 2015.
[2] Data derived from 2012, 2013, 2014 Form 10-K.
[3] The Laclede Group Acquires Alabama Gas Corporation: http://www.prnewswire.com/news-releases/the-laclede-group-acquires-alabama-gas-corporation-273556051.html, Sept. 2, 2014
[4] UGI Corp. acquires LP gas business in France: http://www.lpgasmagazine.com/ugi-corp-acquires-lp-gas-business-in-france/
[5] "N/A" represents data not reported.
[6] Data derived from SNL Financial, Consolidated Financial Statements, Audited Financial Statements, Municiple Financial Reports and Company Annual Reports (figures represent average of years 2012-2014)
[7] "Fortis to sell off Properties division, focus on utilities": http://www.cbc.ca/news/canada/newfoundland-labrador/fortis-to-sell-off-properties-division-focus-on-utilities-1.2890431
[8] "Southern Co. to Buy AGL Resources": http://www.wsj.com/articles/southern-co-to-buy-agl-resources-for-8-billion-1440416621
[9] "Analsts increase valuations for Emera, TECO as companies tout deal" SNL Financial Article, September 8, 2015

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1990	-14.8	-3.11	--	--	0.1	1.9	4.8	5.4	10.76	8.55	16.12	1.96	7.7	5.6	1.17
1991	12.02	30.47	--	--	-2.1	-0.2	5.6	4.2	9.42	7.86	15.55	1.86	9.8	6.8	1.15
1992	-1.43	7.62	--	--	0.9	3.4	1.4	3.0	8.05	7.01	17.28	2.10	10.7	7.5	1.21
1993	32.55	10.08	--	--	2.6	2.9	1.9	3.0	7.22	5.87	20.04	2.51	10.8	6.9	1.29
1994	-0.18	1.32	--	--	4.6	4.1	0.1	2.6	8.42	7.09	22.95	3.00	9.6	6.1	1.37
1995	14.53	37.58	--	--	2.7	2.5	2.2	2.8	8.08	6.57	24.82	3.19	8.6	5.6	1.37
1996	28.35	22.96	--	--	1.7	3.7	1.5	3.0	7.20	6.44	25.94	3.13	8.8	5.4	1.36
1997	14.98	33.36	--	--	4.3	4.5	1.7	2.3	6.11	6.35	26.82	3.51	8.4	4.9	1.38
1998	-1.58	28.58	--	--	4.2	4.4	1.0	1.6	5.30	5.26	28.67	3.94	7.7	4.5	1.48
1999	31.71	21.04	--	--	5.2	4.8	1.8	2.2	5.55	5.65	30.75	3.96	7.0	4.2	1.49
2000	7.41	-9.11	--	--	5.1	4.1	2.7	3.4	5.89	6.03	32.57	3.97	6.1	4.0	1.49
2001	-12.57	-11.89	--	--	1.7	1.1	2.5	2.8	5.47	5.02	30.90	3.82	6.5	4.7	1.55
2002	-12.44	-22.10	--	--	2.8	1.8	2.2	1.6	5.29	4.61	29.26	3.76	7.0	5.8	1.57
2003	26.72	28.68	24.96	26.27	2.0	2.5	2.8	2.3	4.79	4.01	26.34	3.02	6.9	6.0	1.40
2004	14.48	10.88	9.42	24.28	3.2	3.5	1.8	2.7	4.59	4.27	26.36	2.74	6.4	5.5	1.30
2005	24.13	4.91	38.30	16.83	3.1	3.1	2.2	3.4	4.05	4.29	26.01	2.49	6.0	5.1	1.21
2006	17.26	15.79	7.01	21.00	2.7	2.7	2.0	3.2	4.22	4.80	24.23	2.25	5.5	4.6	1.13
2007	9.83	5.49	11.80	19.38	2.1	1.9	2.2	2.8	4.28	4.63	22.64	2.07	5.2	4.6	1.07
2008	-33.00	-37.00	-20.46	-28.98	1.1	-0.3	2.3	3.8	3.58	3.66	22.41	2.10	5.3	5.8	1.07
2009	35.05	26.46	19.00	11.92	-2.8	-3.1	0.3	-0.4	3.29	3.26	17.25	1.93	7.3	9.3	1.14
2010	17.61	15.06	18.42	5.46	3.2	2.4	1.8	1.6	3.20	3.22	17.75	1.85	7.1	9.6	1.03
2011	-8.71	2.10	6.47	19.95	2.6	1.8	2.9	3.2	2.78	2.78	18.72	1.84	6.5	8.9	0.99
2012	7.19	16.00	4.00	0.47	1.8	2.2	1.5	2.1	1.85	1.80	18.59	1.89	6.3	8.1	1.00
2013	12.98	32.39	-3.71	14.79	2.0	2.2	0.9	1.5	2.26	2.35	19.63	1.79	7.1	7.4	1.03
2014	10.55	13.68	16.08	28.98	2.5	2.4	2	1.6	2.23	2.53	22.37	1.79	6.7	6.2	1.10
25-year Avg.	9.31	11.25	--	--	2.29	2.41	2.08	2.63	5.36	4.96	23.36	2.66	7.40	6.12	1.25
10-year Avg.	9.29	9.49	9.69	10.98	1.83	1.53	1.81	2.28	3.17	3.33	20.96	2.00	6.30	6.95	1.08
5-year Avg.	7.92	15.85	8.25	13.93	2.42	2.20	1.82	2.00	2.46	2.54	19.41	1.83	6.74	8.02	1.03
Correlation	0.71		0.64		0.86		0.72		0.97		0.90		0.21		--
Consensus Forecasts [15]															
2015					2.00	2.90	1.00	0.10	1.60	2.20			6.80	5.40	1.28
2016					2.10	2.80	2.10	2.20	2.10	2.80			6.60	5.00	1.26
2017					2.30	2.60	2.10	2.30	3.20	3.90					1.20

Notes:

[1] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[2] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[3] Source: Bloomberg Professional; includes price appreciation and dividend yield, however dividend data for S&P/TSX Utilities not available prior to 2003
[4] Source: Bloomberg Professional; includes price appreciation and dividend yield
[5] Source: Statistics Canada; expenditure-based GDP at market prices, chained 2007 prices, seasonally adjusted
[6] Source: U.S. Bureau of Economic Analysis
[7] Source: Statistics Canada; not seasonally adjusted
[8] Source: U.S. Bureau of Labor Statistics; not seasonally adjusted, U.S. city average, all items
[9] Source: Bank of Canada
[10] Source: Bloomberg Professional
[11] Source: Government of Canada (exports to United States, merchandise only), Office of the United States Trade Representative (exports to Canada, merchandise only), United States Census Bureau (Trade in Goods with Canada), The World Bank (Total GDP), U.S. Bureau of Economic Analysis (U.S. GDP)
[12] Source: 1989-2012: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted, 2013: Statistics Canada
[13] Source: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted
[14] Source: Federal Reserve Economic Data
[15] Source: Consensus Forecasts, Survey Date April 13, 2015

FortisBC Energy Inc.

Canadian & U.S. Bond Yield Averages
January 2008 - August 2015

			[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
			Gov of Canada 30-Year	Canadian Average	Canadian Public Utility Bonds		Utility Bond ($U.S.)	Canadian Credit Spreads		U.S. Credit Spread
Line No.			T-Bonds	Corporate A	A-Rated	BBB-Rated	BBB+-Rated	A-Rated	BBB-Rated	BBB+-Rated
1	2008	JAN	4.11	5.43	5.37	5.80	6.11	1.27	1.69	2.00
2		FEB	4.19	5.57	5.53	5.87	6.22	1.34	1.67	2.03
3		MAR	4.01	5.42	5.38	5.74	6.24	1.37	1.73	2.23
4		APR	4.11	5.58	5.56	5.88	6.24	1.45	1.77	2.13
5		MAY	4.09	5.47	5.50	5.76	6.26	1.41	1.67	2.17
6		JUN	4.13	5.50	5.57	5.88	6.36	1.44	1.74	2.23
7		JUL	4.10	5.54	5.59	5.93	6.40	1.49	1.82	2.29
8		AUG	4.04	5.59	5.58	5.88	6.41	1.54	1.84	2.38
9		SEP	4.03	5.85	5.81	6.01	6.31	1.78	1.98	2.29
10		OCT	4.18	6.50	6.39	6.73	6.86	2.21	2.56	2.68
11		NOV	4.13	6.89	6.78	7.04	7.85	2.64	2.91	3.72
12		DEC	3.62	6.98	6.58	6.84	7.16	2.97	3.23	3.55
13	2009	JAN	3.62	7.22	6.62	6.99	6.62	3.00	3.37	3.00
14		FEB	3.68	6.99	6.65	6.89	6.89	2.97	3.22	3.21
15		MAR	3.63	6.71	6.57	6.80	7.24	2.95	3.18	3.61
16		APR	3.70	6.68	6.45	6.75	7.46	2.76	3.06	3.77
17		MAY	3.93	6.64	6.30	6.62	7.20	2.37	2.69	3.27
18		JUN	3.96	6.27	5.86	6.20	6.75	1.91	2.25	2.79
19		JUL	3.96	6.07	5.65	6.01	6.44	1.70	2.05	2.49
20		AUG	3.95	5.77	5.43	5.72	5.98	1.47	1.76	2.03
21		SEP	3.89	5.62	5.30	5.59	5.75	1.41	1.70	1.85
22		OCT	3.93	5.70	5.35	5.59	5.86	1.42	1.66	1.93
23		NOV	3.94	5.68	5.36	5.60	5.94	1.42	1.65	1.99
24		DEC	4.01	5.75	5.50	5.75	6.05	1.49	1.74	2.04
25	2010	JAN	4.05	5.76	5.46	5.78	5.96	1.41	1.73	1.90
26		FEB	4.04	5.72	5.43	5.77	6.04	1.39	1.73	2.01
27		MAR	4.06	5.69	5.39	5.68	6.00	1.33	1.61	1.94
28		APR	4.07	5.54	5.35	5.59	5.96	1.28	1.51	1.89
29		MAY	3.83	5.41	5.29	5.45	5.62	1.46	1.62	1.78
30		JUN	3.74	5.34	5.31	5.47	5.62	1.57	1.73	1.88
31		JUL	3.73	5.28	5.23	5.41	5.45	1.50	1.68	1.71
32		AUG	3.57	5.14	5.06	5.23	5.15	1.49	1.66	1.58
33		SEP	3.48	5.09	5.02	5.13	5.18	1.54	1.65	1.70
34		OCT	3.44	4.99	4.93	5.05	5.32	1.50	1.61	1.88
35		NOV	3.58	5.06	4.99	5.11	5.65	1.41	1.53	2.07
36		DEC	3.62	5.15	5.04	5.22	5.85	1.42	1.60	2.24

FortisBC Energy Inc.

Canadian & U.S. Bond Yield Averages
January 2008 - August 2015

			[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
			Gov of Canada 30-Year	Canadian Average	Canadian Public Utility Bonds		Utility Bond ($U.S.)	Canadian Credit Spreads		U.S. Credit Spread
Line No.			T-Bonds	Corporate A	A-Rated	BBB-Rated	BBB+-Rated	A-Rated	BBB-Rated	BBB+-Rated
37	2011	JAN	3.68	5.14	5.07	5.27	5.90	1.39	1.59	2.22
38		FEB	3.80	5.19	5.15	5.33	5.90	1.35	1.53	2.10
39		MAR	3.74	5.15	5.10	5.24	5.77	1.36	1.51	2.03
40		APR	3.76	5.18	5.16	5.30	5.76	1.40	1.54	2.00
41		MAY	3.57	5.00	5.00	5.11	5.54	1.43	1.54	1.97
42		JUN	3.46	4.91	4.91	4.98	5.57	1.45	1.52	2.11
43		JUL	3.41	4.83	4.84	4.94	5.58	1.44	1.53	2.18
44		AUG	3.08	4.57	4.58	4.69	5.03	1.50	1.62	1.96
45		SEP	2.85	4.47	4.46	4.56	4.75	1.60	1.70	1.90
46		OCT	2.90	4.54	4.53	4.60	4.82	1.62	1.70	1.91
47		NOV	2.73	4.38	4.33	4.42	4.69	1.59	1.69	1.96
48		DEC	2.56	4.27	4.15	4.24	4.76	1.59	1.69	2.20
49	2012	JAN	2.56	4.13	4.04	4.11	4.68	1.48	1.55	2.12
50		FEB	2.61	4.01	4.01	4.07	4.56	1.39	1.46	1.95
51		MAR	2.67	4.05	4.04	4.07	4.62	1.37	1.40	1.95
52		APR	2.62	4.03	4.00	4.11	4.54	1.38	1.49	1.91
53		MAY	2.46	3.94	3.95	4.08	4.31	1.49	1.63	1.85
54		JUN	2.33	3.88	3.91	4.03	4.17	1.58	1.70	1.84
55		JUL	2.27	3.83	3.82	3.94	4.00	1.55	1.67	1.73
56		AUG	2.38	3.88	3.86	3.99	4.04	1.48	1.61	1.66
57		SEP	2.41	3.89	3.87	3.97	4.04	1.46	1.56	1.63
58		OCT	2.41	3.85	3.85	3.95	3.99	1.45	1.54	1.58
59		NOV	2.33	3.77	3.81	3.87	3.91	1.48	1.55	1.58
60		DEC	2.36	3.76	3.82	3.87	4.06	1.46	1.51	1.70
61	2013	JAN	2.50	3.86	3.90	3.97	4.20	1.40	1.47	1.70
62		FEB	2.60	3.96	3.99	4.11	4.24	1.40	1.52	1.65
63		MAR	2.55	3.92	3.95	4.07	4.26	1.40	1.52	1.71
64		APR	2.40	3.76	3.81	3.91	4.06	1.41	1.51	1.66
65		MAY	2.53	3.87	3.91	4.00	4.22	1.38	1.48	1.70
66		JUN	2.77	4.10	4.13	4.22	4.59	1.36	1.45	1.83
67		JUL	2.93	4.27	4.31	4.43	4.74	1.39	1.50	1.81
68		AUG	3.09	4.42	4.48	4.58	4.82	1.39	1.49	1.73
69		SEP	3.19	4.59	4.67	4.74	4.91	1.48	1.55	1.72
70		OCT	3.09	4.52	4.56	4.64	4.87	1.47	1.55	1.77
71		NOV	3.13	4.53	4.55	4.61	4.97	1.42	1.48	1.84
72		DEC	3.22	4.61	4.61	4.68	4.97	1.39	1.47	1.75
73	2014	JAN	3.08	4.45	4.43	4.52	4.77	1.35	1.44	1.68
74		FEB	3.01	4.37	4.36	4.46	4.63	1.35	1.46	1.63
75		MAR	2.97	4.31	4.29	4.39	4.63	1.32	1.42	1.66
76		APR	2.96	4.23	4.22	4.33	4.54	1.26	1.37	1.58
77		MAY	2.85	4.22	4.18	4.27	4.40	1.33	1.42	1.55
78		JUN	2.83	4.22	4.18	4.25	4.44	1.34	1.42	1.61
79		JUL	2.74	4.12	4.09	4.15	4.36	1.34	1.41	1.62
80		AUG	2.62	4.04	4.01	4.08	4.34	1.39	1.46	1.72
81		SEP	2.70	4.11	4.09	4.17	n/a	1.39	1.47	n/a
82		OCT	2.56	4.00	3.98	4.05	n/a	1.42	1.50	n/a
83		NOV	2.57	4.03	4.01	4.11	4.36	1.44	1.55	1.79
84		DEC	2.40	3.90	3.86	3.98	4.27	1.47	1.58	1.88

FortisBC Energy Inc.

Canadian & U.S. Bond Yield Averages
January 2008 - August 2015

			[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
			Gov of Canada 30-Year	Canadian Average	Canadian Public Utility Bonds		Utility Bond ($U.S.)	Canadian Credit Spreads		U.S. Credit Spread
Line No.			T-Bonds	Corporate A	A-Rated	BBB-Rated	BBB+-Rated	A-Rated	BBB-Rated	BBB+-Rated
85	2015	JAN	2.11	3.63	3.59	3.71	3.86	1.48	1.60	1.75
86		FEB	2.01	3.50	3.46	3.61	3.88	1.46	1.61	1.88
87		MAR	2.05	3.50	3.46	3.58	3.94	1.41	1.53	1.89
88		APR	2.04	3.49	3.45	3.65	3.92	1.41	1.61	1.88
89		MAY	2.34	3.82	3.78	4.04	4.35	1.44	1.70	2.01
90		JUN	2.38	3.93	3.89	4.15	4.60	1.51	1.78	2.23
91		JUL	2.24	3.92	3.89	4.14	4.60	1.65	1.90	2.36
92		AUG	2.11	3.92	3.89	4.20	4.47	1.78	2.09	2.36

Note: September and October 2014 Utility Bond ($U.S.) BBB+-Rated is n/a due to Bloomberg data unavailability.

Sources:

[A] Bloomberg, Canadian Government Generic 30-Year Treasury Bond
[B] Bloomberg, Canadian Corporate (A) Average Bond Index
[C] Bloomberg, Canadian A-Rated Utility Bond Index
[D] Bloomberg, Canadian BBB-Rated Utility Bond Index
[E] Bloomberg, USD BBB+-Rated Utility Bond Index
[F] Equals [C] − [A]
[G] Equals [D] − [A]
[H] Equals [E] - [A]

Canadian Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Sun Life Financial Inc	SLF	612.078	41.700	25,524	1.8010%	3.65%	8.50%	0.0656%	0.1531%
Enghouse Systems Ltd	ESL	26.285	48.690	1,280	0.0000%	0.99%	n/a	0.0000%	n/a
H&R Real Estate Investment Trust	HR-U	276.087	22.440	6,195	0.0000%	6.02%	n/a	0.0000%	n/a
West Fraser Timber Co Ltd	WFT	81.248	68.630	5,576	0.0000%	0.41%	n/a	0.0000%	n/a
Brookfield Asset Management Inc	BAM/A	980.619	43.640	42,794	3.0197%	1.37%	13.00%	0.0415%	0.3926%
Enbridge Income Fund Holdings Inc	ENF	70.351	34.530	2,429	0.0000%	4.47%	n/a	0.0000%	n/a
Saputo Inc	SAP	392.510	30.210	11,858	0.8367%	1.72%	6.67%	0.0144%	0.0558%
Pembina Pipeline Corp	PPL	332.338	40.370	13,416	0.9467%	4.53%	6.60%	0.0429%	0.0625%
Secure Energy Services Inc	SES	136.107	12.780	1,739	0.0000%	1.88%	n/a	0.0000%	n/a
Ritchie Bros Auctioneers Inc	RBA	106.045	34.850	3,696	0.2608%	2.01%	13.22%	0.0052%	0.0345%
Seven Generations Energy Ltd	VII	245.153	16.320	4,001	0.0000%	n/a	n/a	n/a	n/a
Performance Sports Group Ltd	PSG	45.526	22.480	1,023	0.0000%	n/a	13.69%	n/a	0.0000%
Gildan Activewear Inc	GIL	242.394	41.490	10,057	0.7097%	0.77%	17.15%	0.0055%	0.1217%
Descartes Systems Group Inc/The	DSG	75.495	20.050	1,514	0.0000%	n/a	15.00%	n/a	0.0000%
Industrial Alliance Insurance & Financial Services Inc	IAG	101.174	42.010	4,250	0.2999%	2.67%	3.40%	0.0080%	0.0102%
Innergex Renewable Energy Inc	INE	101.269	10.620	1,075	0.0000%	5.84%	n/a	0.0000%	n/a
Manulife Financial Corp	MFC	1,970.270	23.210	45,730	3.2269%	2.93%	7.10%	0.0945%	0.2291%
Element Financial Corp	EFN	264.204	19.750	5,218	0.0000%	n/a	n/a	n/a	n/a
FirstService Corp	FSV	34.645	34.720	1,203	0.0849%	1.42%	15.00%	0.0012%	0.0127%
Canadian Pacific Railway Ltd	CP	164.062	200.020	32,816	2.3156%	0.70%	15.30%	0.0162%	0.3544%
Husky Energy Inc	HSE	983.840	23.890	23,504	1.6585%	5.02%	17.30%	0.0833%	0.2869%
Bonavista Energy Corp	BNP	206.603	6.790	1,403	0.0000%	6.19%	n/a	0.0000%	n/a
Baytex Energy Corp	BTE	205.599	19.430	3,995	0.2819%	6.18%	-101.42%	0.0174%	-0.2859%
Crescent Point Energy Corp	CPG	452.279	25.630	11,592	0.8180%	10.77%	-14.60%	0.0881%	-0.1194%
Centerra Gold Inc	CG	236.475	7.100	1,679	0.1185%	2.25%	0.50%	0.0027%	0.0006%
Newalta Corp	NAL	56.237	14.220	800	0.0000%	3.52%	n/a	0.0000%	n/a
Alaris Royalty Corp	AD	31.996	30.490	976	0.0000%	5.31%	n/a	0.0000%	n/a
Intact Financial Corp	IFC	131.543	86.790	11,417	0.0000%	2.44%	n/a	0.0000%	n/a
George Weston Ltd	WN	127.919	98.110	12,550	0.8856%	1.73%	36.10%	0.0153%	0.3197%
MEG Energy Corp	MEG	223.847	20.400	4,566	0.0000%	n/a	n/a	n/a	n/a
DREAM Unlimited Corp	DRM	75.993	9.690	736	0.0000%	n/a	n/a	n/a	n/a
PrairieSky Royalty Ltd	PSK	149.409	31.510	4,708	0.0000%	4.13%	n/a	0.0000%	n/a
Cameco Corp	CCO	395.793	17.870	7,073	0.4991%	2.24%	40.91%	0.0112%	0.2042%
Turquoise Hill Resources Ltd	TRQ	2,012.309	4.750	9,558	0.0000%	n/a	n/a	n/a	n/a
Canfor Corp	CFP	134.155	27.200	3,649	0.0000%	n/a	n/a	n/a	n/a
ProMetic Life Sciences Inc	PLI	574.974	2.350	1,351	0.0000%	n/a	n/a	n/a	n/a
Interfor Corp	IFP	70.030	20.490	1,435	0.0000%	n/a	n/a	n/a	n/a
Cott Corp	BCB	109.375	12.210	1,335	0.0000%	2.45%	n/a	0.0000%	n/a
Franco-Nevada Corp	FNV	156.480	59.570	9,322	0.6578%	1.74%	5.00%	0.0114%	0.0329%
Cenovus Energy Inc	CVE	828.436	19.970	16,544	1.1674%	5.33%	20.40%	0.0622%	0.2381%
AutoCanada Inc	ACQ	24.510	41.300	1,012	0.0000%	2.42%	n/a	0.0000%	n/a
Athabasca Oil Corp	ATH	402.944	2.040	822	0.0000%	n/a	n/a	n/a	n/a
Pretium Resources Inc	PVG	133.422	6.760	902	0.0000%	n/a	n/a	n/a	n/a
Empire Co Ltd	EMP/A	58.049	87.970	5,107	0.3603%	1.36%	7.00%	0.0049%	0.0252%
Loblaw Cos Ltd	L	412.628	63.080	26,029	1.8367%	1.59%	14.28%	0.0291%	0.2623%
Metro Inc	MRU	248.891	33.520	8,343	0.5887%	1.39%	11.10%	0.0082%	0.0653%
Tourmaline Oil Corp	TOU	216.063	37.520	8,107	0.0000%	n/a	n/a	n/a	n/a
Bank of Montreal	BMO	644.256	74.010	47,681	3.3646%	4.43%	4.40%	0.1491%	0.1480%
Bank of Nova Scotia/The	BNS	1,209.962	64.470	78,006	5.5044%	4.22%	5.73%	0.2322%	0.3156%
Canadian Imperial Bank of Commerce/Canada	CM	397.276	92.070	36,577	2.5810%	4.74%	8.80%	0.1222%	0.2271%
Canadian Western Bank	CWB	80.451	28.770	2,315	0.0000%	3.06%	n/a	0.0000%	n/a
Laurentian Bank of Canada	LB	28.945	48.140	1,393	0.0000%	4.65%	n/a	0.0000%	n/a
Concordia Healthcare Corp	CXR	33.265	90.250	3,002	0.0000%	0.42%	n/a	0.0000%	n/a
National Bank of Canada	NA	329.390	46.920	15,455	1.0906%	4.43%	8.30%	0.0483%	0.0905%
Toronto-Dominion Bank/The	TD	1,851.851	53.040	98,222	6.9309%	3.85%	12.00%	0.2666%	0.8317%
Amaya Inc	AYA	133.384	34.220	4,564	0.0000%	n/a	n/a	n/a	n/a
Osisko Gold Royalties Ltd	OR	94.142	15.720	1,480	0.1044%	0.76%	50.00%	0.0008%	0.0522%
Sherritt International Corp	S	297.300	2.090	621	0.0000%	1.91%	n/a	0.0000%	n/a
TORC Oil & Gas Ltd	TOG	156.916	8.700	1,365	0.0963%	6.21%	26.00%	0.0060%	0.0250%
TMX Group Ltd	X	54.172	53.150	2,879	0.0000%	3.01%	n/a	0.0000%	n/a
Ensign Energy Services Inc	ESI	153.060	12.240	1,873	0.0000%	3.92%	n/a	0.0000%	n/a
Parex Resources Inc	PXT	149.828	10.470	1,569	0.0000%	n/a	n/a	n/a	n/a
Trican Well Service Ltd	TCW	148.918	4.150	618	0.0000%	n/a	10.05%	n/a	0.0000%
Aimia Inc	AIM	164.724	13.600	2,240	0.0000%	5.59%	n/a	0.0000%	n/a
Pure Industrial Real Estate Trust	AAR-U	189.411	4.710	892	0.0000%	6.62%	n/a	0.0000%	n/a
Computer Modelling Group Ltd	CMG	78.543	12.660	994	0.0702%	3.16%	32.70%	0.0022%	0.0229%
Genworth MI Canada Inc	MIC	93.172	32.800	3,056	0.0000%	4.76%	n/a	0.0000%	n/a
Chemtrade Logistics Income Fund	CHE-U	68.275	20.300	1,386	0.0000%	5.91%	n/a	0.0000%	n/a
Manitoba Telecom Services Inc	MBT	78.935	27.910	2,203	0.1555%	4.66%	0.70%	0.0072%	0.0011%
Methanex Corp	MX	91.085	69.720	6,350	0.0000%	1.94%	n/a	0.0000%	n/a
Restaurant Brands International Inc	QSR	202.304	47.870	9,684	0.6834%	1.04%	18.52%	0.0071%	0.1265%
Constellation Software Inc/Canada	CSU	21.192	495.860	10,508	0.0000%	0.99%	n/a	0.0000%	n/a

Canadian Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68	9.78%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Suncor Energy Inc	SU	1,445.656	34.400	49,731	3.5092%	3.26%	16.90%	0.1143%	0.5930%
Parkland Fuel Corp	PKI	89.708	24.880	2,232	0.0000%	4.34%	n/a	0.0000%	n/a
Lundin Mining Corp	LUN	719.326	5.130	3,690	0.0000%	n/a	22.58%	n/a	0.0000%
Novagold Resources Inc	NG	317.862	4.290	1,364	0.0000%	n/a	n/a	n/a	n/a
Kelt Exploration Ltd	KEL	158.424	8.440	1,337	0.0000%	n/a	n/a	n/a	n/a
Aecon Group Inc	ARE	56.448	12.750	720	0.0508%	3.14%	-4.00%	0.0016%	-0.0020%
Atco Ltd/Canada	ACO/X	101.502	39.490	4,008	0.0000%	2.51%	n/a	0.0000%	n/a
Intertain Group Ltd/The	IT	72.353	17.230	1,247	0.0000%	n/a	n/a	n/a	n/a
TransForce Inc	TFI	101.212	25.330	2,564	0.0000%	2.68%	n/a	0.0000%	n/a
Bonterra Energy Corp	BNE	32.170	31.490	1,013	0.0000%	5.72%	n/a	0.0000%	n/a
Calfrac Well Services Ltd	CFW	95.868	7.710	739	0.0000%	3.24%	n/a	0.0000%	n/a
Dorel Industries Inc	DII/B	28.127	33.410	940	0.0663%	4.39%	10.00%	0.0029%	0.0066%
Royal Bank of Canada	RY	1,443.102	76.380	110,224	7.7778%	4.03%	9.05%	0.3136%	0.7039%
Crombie Real Estate Investment Trust	CRR-U	77.248	12.470	963	0.0000%	7.14%	n/a	0.0000%	n/a
Russel Metals Inc	RUS	61.702	22.730	1,402	0.0990%	6.69%	4.50%	0.0066%	0.0045%
Stantec Inc	STN	93.976	36.500	3,430	0.2420%	1.15%	18.00%	0.0028%	0.0436%
Transcontinental Inc	TCL/A	63.246	15.390	973	0.0687%	4.42%	-2.00%	0.0030%	-0.0014%
Bankers Petroleum Ltd	BNK	261.394	3.100	810	0.0000%	n/a	n/a	n/a	n/a
Home Capital Group Inc	HCG	70.226	43.280	3,039	0.0000%	2.03%	n/a	0.0000%	n/a
Gran Tierra Energy Inc	GTE	277.211	3.740	1,037	0.0000%	n/a	n/a	n/a	n/a
Fortuna Silver Mines Inc	FVI	128.846	4.550	586	0.0000%	n/a	n/a	n/a	n/a
Hudson's Bay Co	HBC	182.100	27.750	5,053	0.3566%	0.72%	14.64%	0.0026%	0.0522%
Painted Pony Petroleum Ltd	PPY	99.651	7.960	793	0.0000%	n/a	n/a	n/a	n/a
Linamar Corp	LNR	65.112	81.120	5,282	0.0000%	0.49%	n/a	0.0000%	n/a
Nevsun Resources Ltd	NSU	199.658	4.700	938	0.0000%	4.20%	n/a	0.0000%	n/a
North West Co Inc/The	NWC	48.499	24.760	1,201	0.0000%	4.69%	n/a	0.0000%	n/a
Celestica Inc	CLS	150.238	14.540	2,184	0.0000%	n/a	n/a	n/a	n/a
SEMAFO Inc	SMF	294.086	3.360	988	0.0000%	n/a	-10.00%	n/a	0.0000%
ShawCor Ltd	SCL	64.499	36.590	2,360	0.0000%	1.64%	n/a	0.0000%	n/a
RONA Inc	RON	108.037	15.180	1,640	0.1157%	0.92%	0.38%	0.0011%	0.0004%
Silver Standard Resources Inc	SSO	80.754	7.850	634	0.0000%	n/a	3.00%	n/a	0.0000%
BlackBerry Ltd	BB	529.431	10.210	5,405	0.0000%	n/a	-17.60%	n/a	0.0000%
Granite Real Estate Investment Trust	GRT-U	47.014	42.960	2,020	0.0000%	5.36%	n/a	0.0000%	n/a
Toromont Industries Ltd	TIH	77.577	31.240	2,424	0.1710%	2.18%	7.26%	0.0037%	0.0124%
First Majestic Silver Corp	FR	122.215	6.050	739	0.0000%	n/a	n/a	n/a	n/a
Advantage Oil & Gas Ltd	AAV	170.666	7.900	1,348	0.0000%	n/a	n/a	n/a	n/a
Colliers International Group Inc	CIG	36.643	47.800	1,752	0.1236%	1.05%	20.00%	0.0013%	0.0247%
Dominion Diamond Corp	DDC	85.206	17.500	1,491	0.0000%	2.75%	n/a	0.0000%	n/a
Cogeco Cable Inc	CCA	33.532	72.240	2,422	0.1709%	1.94%	13.37%	0.0033%	0.0229%
Canadian Real Estate Investment Trust	REF-U	71.964	42.450	3,055	0.0000%	4.24%	n/a	0.0000%	n/a
First Capital Realty Inc	FCR	222.046	17.880	3,970	0.0000%	4.81%	n/a	0.0000%	n/a
First Quantum Minerals Ltd	FM	688.967	16.330	11,251	0.7939%	0.60%	52.31%	0.0047%	0.4153%
Pason Systems Inc	PSI	83.609	22.350	1,869	0.0000%	3.04%	n/a	0.0000%	n/a
Rogers Communications Inc	RCI/B	402.304	44.300	17,822	1.2576%	4.33%	3.67%	0.0545%	0.0462%
Jean Coutu Group PJC Inc/The	PJC/A	83.566	23.200	1,939	0.1368%	1.90%	6.40%	0.0026%	0.0088%
Major Drilling Group International Inc	MDI	80.137	6.250	501	0.0000%	0.64%	n/a	0.0000%	n/a
Mullen Group Ltd	MTL	91.654	20.410	1,871	0.0000%	5.88%	n/a	0.0000%	n/a
Maple Leaf Foods Inc	MFI	142.956	23.690	3,387	0.0000%	1.35%	n/a	0.0000%	n/a
HudBay Minerals Inc	HBM	235.054	10.400	2,445	0.1725%	0.19%	43.00%	0.0003%	0.0742%
Labrador Iron Ore Royalty Corp	LIF	64.000	14.260	913	0.0644%	7.01%	15.20%	0.0045%	0.0098%
Dream Office Real Estate Investment Trust	D-U	108.123	24.540	2,653	0.0000%	9.13%	n/a	0.0000%	n/a
CCL Industries Inc	CCL/B	32.436	153.200	4,969	0.0000%	0.98%	n/a	0.0000%	n/a
Extendicare Inc	EXE	87.530	7.570	663	0.0000%	6.34%	n/a	0.0000%	n/a
Superior Plus Corp	SPB	126.185	12.560	1,585	0.0000%	5.73%	n/a	0.0000%	n/a
Freehold Royalties Ltd	FRU	97.990	16.140	1,582	0.0000%	6.69%	n/a	0.0000%	n/a
Encana Corp	ECA	840.818	13.770	11,578	0.8170%	2.51%	-9.50%	0.0205%	-0.0776%
Westshore Terminals Investment Corp	WTE	74.250	30.410	2,258	0.0000%	4.34%	n/a	0.0000%	n/a
Northland Power Inc	NPI	167.951	15.820	2,657	0.0000%	6.83%	n/a	0.0000%	n/a
Canadian Apartment Properties REIT	CAR-U	116.433	27.600	3,214	0.0000%	4.42%	n/a	0.0000%	n/a
Inter Pipeline Ltd	IPL	334.580	28.700	9,602	0.0000%	5.12%	n/a	0.0000%	n/a
Peyto Exploration & Development Corp	PEY	158.958	30.530	4,853	0.0000%	4.32%	n/a	0.0000%	n/a
Avigilon Corp	AVO	46.638	16.840	785	0.0000%	n/a	n/a	n/a	n/a
Algonquin Power & Utilities Corp	AQN	238.132	9.360	2,229	0.0000%	5.08%	n/a	0.0000%	n/a
Veresen Inc	VSN	289.167	16.890	4,884	0.0000%	5.92%	n/a	0.0000%	n/a
Dream Global Real Estate Investment Trust	DRG-U	109.015	9.930	1,083	0.0000%	8.06%	n/a	0.0000%	n/a
Smart Real Estate Investment Trust	SRU-U	124.504	28.920	3,601	0.0000%	5.54%	n/a	0.0000%	n/a
Alacer Gold Corp	ASR	290.918	2.930	852	0.0000%	n/a	-0.18%	n/a	0.0000%
Pan American Silver Corp	PAA	151.643	10.740	1,629	0.1149%	2.27%	4.00%	0.0026%	0.0046%
AltaGas Ltd	ALA	134.833	38.040	5,129	0.0000%	5.05%	n/a	0.0000%	n/a
Cominar Real Estate Investment Trust	CUF-U	167.877	17.730	2,976	0.0000%	8.29%	n/a	0.0000%	n/a
DH Corp	DH	105.568	39.920	4,214	0.0000%	3.21%	n/a	0.0000%	n/a
WestJet Airlines Ltd	WJA	107.674	26.360	2,838	0.2003%	2.12%	12.98%	0.0043%	0.0260%

Canadian Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Corus Entertainment Inc	CJR/B	83.343	16.670	1,389	0.0000%	6.84%	n/a	0.0000%	n/a
Emera Inc	EMA	142.101	39.340	5,590	0.0000%	4.07%	n/a	0.0000%	n/a
Birchcliff Energy Ltd	BIR	152.290	6.970	1,061	0.0000%	n/a	n/a	n/a	n/a
MacDonald Dettwiler & Associates Ltd	MDA	36.133	91.270	3,298	0.0000%	1.62%	n/a	0.0000%	n/a
Torex Gold Resources Inc	TXG	785.372	1.130	887	0.0000%	n/a	n/a	n/a	n/a
Trinidad Drilling Ltd	TDG	133.425	4.040	539	0.0000%	4.95%	n/a	0.0000%	n/a
Just Energy Group Inc	JE	146.559	6.510	954	0.0000%	7.68%	n/a	0.0000%	n/a
Progressive Waste Solutions Ltd	BIN	115.180	33.500	3,859	0.2723%	1.91%	9.40%	0.0052%	0.0256%
Northern Property Real Estate Investment Trust	NPR-U	31.822	22.380	712	0.0000%	7.28%	n/a	0.0000%	n/a
Allied Properties Real Estate Investment Trust	AP-U	77.283	35.440	2,739	0.0000%	4.12%	n/a	0.0000%	n/a
Keyera Corp	KEY	168.832	41.700	7,040	0.0000%	3.31%	n/a	0.0000%	n/a
Power Financial Corp	PWF	711.174	35.870	25,510	1.8001%	4.15%	12.60%	0.0748%	0.2268%
NuVista Energy Ltd	NVA	152.992	6.690	1,024	0.0000%	n/a	n/a	n/a	n/a
Canadian Energy Services & Technology Corp	CEU	217.007	7.200	1,562	0.0000%	4.58%	n/a	0.0000%	n/a
Barrick Gold Corp	ABX	1,164.670	13.350	15,548	1.0971%	1.87%	-1.93%	0.0205%	-0.0212%
Crew Energy Inc	CR	140.984	5.710	805	0.0000%	n/a	n/a	n/a	n/a
Cineplex Inc	CGX	63.067	47.020	2,965	0.0000%	3.32%	n/a	0.0000%	n/a
BCE Inc	BCE	847.646	53.060	44,976	3.1737%	4.90%	5.07%	0.1555%	0.1609%
Chartwell Retirement Residences	CSH-U	174.165	11.480	1,999	0.0000%	4.80%	n/a	0.0000%	n/a
Trilogy Energy Corp	TET	105.240	5.650	595	0.0000%	n/a	n/a	n/a	n/a
Black Diamond Group Ltd	BDI	41.086	17.510	719	0.0000%	5.48%	n/a	0.0000%	n/a
Surge Energy Inc	SGY	220.060	3.540	779	0.0000%	8.47%	n/a	0.0000%	n/a
Artis Real Estate Investment Trust	AX-U	134.866	13.710	1,849	0.0000%	7.88%	n/a	0.0000%	n/a
Potash Corp of Saskatchewan Inc	POT	834.228	38.680	32,268	2.2769%	5.01%	6.00%	0.1141%	0.1366%
Detour Gold Corp	DGC	170.563	14.370	2,451	0.0000%	n/a	7.00%	n/a	0.0000%
TransCanada Corp	TRP	708.941	50.760	35,986	0.0000%	4.10%	n/a	0.0000%	n/a
OceanaGold Corp	OGC	303.255	3.090	937	0.0661%	1.62%	-3.00%	0.0011%	-0.0020%
Enerflex Ltd	EFX	78.999	13.500	1,066	0.0000%	2.52%	n/a	0.0000%	n/a
B2Gold Corp	BTO	921.483	1.910	1,760	0.0000%	n/a	51.43%	n/a	0.0000%
Valeant Pharmaceuticals International Inc	VRX	340.859	277.070	94,442	0.0000%	n/a	16.10%	n/a	0.0000%
Dollarama Inc	DOL	129.356	75.700	9,792	0.6910%	0.48%	16.78%	0.0033%	0.1159%
Capital Power Corp	CPX	103.219	21.540	2,223	0.0000%	6.31%	n/a	0.0000%	n/a
Eldorado Gold Corp	ELD	716.587	5.180	3,712	0.2619%	0.39%	13.90%	0.0010%	0.0364%
Onex Corp	OCX	111.049	69.110	7,675	0.0000%	0.36%	n/a	0.0000%	n/a
Tahoe Resources Inc	THO	224.000	15.140	3,391	0.2393%	1.96%	4.77%	0.0047%	0.0114%
Imperial Oil Ltd	IMO	847.599	48.250	40,897	0.0000%	1.08%	n/a	0.0000%	n/a
Air Canada	AC	286.835	13.210	3,789	0.0000%	n/a	40.13%	n/a	0.0000%
ATS Automation Tooling Systems Inc	ATA	91.630	15.290	1,401	0.0000%	n/a	n/a	n/a	n/a
Brookfield Renewable Energy Partners LP/CA	BEP-U	143.401	37.140	5,326	0.0000%	5.58%	n/a	0.0000%	n/a
Alimentation Couche-Tard Inc	ATD/B	419.263	53.430	22,401	1.5807%	0.34%	17.98%	0.0053%	0.2841%
Pacific Exploration and Production Corp	PRE	316.095	4.710	1,489	0.0000%	n/a	n/a	n/a	n/a
Brookfield Property Partners LP	BPY-U	255.863	27.620	7,067	0.0000%	4.79%	n/a	0.0000%	n/a
Agnico Eagle Mines Ltd	AEM	216.202	35.460	7,667	0.5410%	1.12%	4.40%	0.0061%	0.0238%
Bombardier Inc	BBD/B	1,932.014	2.250	4,347	0.0000%	n/a	6.44%	n/a	0.0000%
TELUS Corp	T	605.501	43.030	26,055	1.8385%	3.90%	8.00%	0.0718%	0.1471%
Penn West Petroleum Ltd	PWT	502.163	2.150	1,080	0.0000%	1.86%	n/a	0.0000%	n/a
CAE Inc	CAE	267.181	14.870	3,973	0.2803%	1.88%	10.85%	0.0053%	0.0304%
Canadian Natural Resources Ltd	CNQ	1,094.180	33.900	37,093	2.6174%	2.71%	9.20%	0.0710%	0.2408%
DHX Media Ltd	DHX/B	79.885	9.340	746	0.0000%	0.60%	n/a	0.0000%	n/a
Canadian Tire Corp Ltd	CTC/A	73.603	133.580	9,832	0.6938%	1.57%	8.41%	0.0109%	0.0583%
Primero Mining Corp	P	162.264	4.870	790	0.0000%	n/a	48.78%	n/a	0.0000%
Canadian Utilities Ltd	CU	189.373	35.970	6,812	0.0000%	3.28%	n/a	0.0000%	n/a
Western Forest Products Inc	WEF	395.065	2.230	881	0.0000%	3.59%	n/a	0.0000%	n/a
CGI Group Inc	GIB/A	281.744	48.850	13,763	0.0000%	n/a	11.55%	n/a	0.0000%
EnerCare Inc	ECI	91.941	13.300	1,223	0.0000%	6.32%	n/a	0.0000%	n/a
New Gold Inc	NGD	509.083	3.350	1,705	0.0000%	n/a	3.50%	n/a	0.0000%
Fairfax Financial Holdings Ltd	FFH	22.016	615.880	13,559	0.0000%	1.95%	n/a	0.0000%	n/a

Canadian Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Finning International Inc	FTT	172.374	23.490	4,049	0.2857%	3.11%	10.00%	0.0089%	0.0286%
Badger Daylighting Ltd	BAD	37.046	26.190	970	0.0000%	1.37%	n/a	0.0000%	n/a
Canaccord Genuity Group Inc	CF	102.621	7.780	798	0.0000%	2.57%	n/a	0.0000%	n/a
Fortis Inc/Canada	FTS	277.493	35.080	9,734	0.0000%	3.88%	n/a	0.0000%	n/a
Goldcorp Inc	G	829.793	20.270	16,820	1.1869%	3.65%	14.20%	0.0433%	0.1685%
Great-West Lifeco Inc	GWO	996.699	36.360	36,240	2.5572%	3.59%	10.00%	0.0917%	0.2557%
BRP Inc/CA	DOO	39.215	29.190	1,145	0.0000%	n/a	10.00%	n/a	0.0000%
Enbridge Inc	ENB	856.713	58.410	50,041	3.5310%	3.18%	5.50%	0.1124%	0.1942%
IGM Financial Inc	IGM	249.490	39.780	9,925	0.7003%	5.66%	5.30%	0.0396%	0.0371%
Magna International Inc	MG	410.776	70.100	28,795	2.0319%	1.57%	10.18%	0.0319%	0.2068%
Great Canadian Gaming Corp	GC	69.782	24.010	1,675	0.0000%	n/a	n/a	n/a	n/a
Precision Drilling Corp	PD	292.823	8.400	2,460	0.1736%	3.33%	-27.28%	0.0058%	-0.0473%
Paramount Resources Ltd	POU	106.188	28.700	3,048	0.0000%	n/a	-5.00%	n/a	0.0000%
Shaw Communications Inc	SJR/B	448.986	27.200	12,212	0.8618%	4.36%	5.71%	0.0375%	0.0492%
SNC-Lavalin Group Inc	SNC	152.142	41.960	6,384	0.0000%	2.38%	n/a	0.0000%	n/a
Martinrea International Inc	MRE	85.756	13.350	1,145	0.0808%	0.90%	22.10%	0.0007%	0.0179%
Teck Resources Ltd	TCK/B	566.863	12.380	7,018	0.4952%	2.42%	23.49%	0.0120%	0.1163%
Boardwalk Real Estate Investment Trust	BEI-U	47.479	56.630	2,689	0.0000%	3.60%	n/a	0.0000%	n/a
Thomson Reuters Corp	TRI	784.473	47.560	37,310	2.6327%	3.44%	8.35%	0.0907%	0.2198%
Whitecap Resources Inc	WCP	298.023	13.180	3,928	0.0000%	5.69%	n/a	0.0000%	n/a
Agrium Inc	AGU	143.250	132.370	18,962	1.3380%	3.26%	20.90%	0.0437%	0.2796%
Norbord Inc	NBD	85.323	26.210	2,236	0.0000%	3.82%	n/a	0.0000%	n/a
Pengrowth Energy Corp	PGF	539.684	3.120	1,684	0.0000%	7.69%	n/a	0.0000%	n/a
Kinross Gold Corp	K	1,146.211	2.910	3,335	0.0000%	n/a	-4.80%	n/a	0.0000%
RioCan Real Estate Investment Trust	REI-U	317.127	26.770	8,489	0.0000%	5.27%	n/a	0.0000%	n/a
TransAlta Corp	TA	278.670	9.680	2,698	0.1903%	7.44%	31.60%	0.0142%	0.0601%
Bellatrix Exploration Ltd	BXE	191.957	2.910	559	0.0000%	n/a	n/a	n/a	n/a
Gibson Energy Inc	GEI	125.616	22.550	2,833	0.0000%	5.68%	n/a	0.0000%	n/a
Vermilion Energy Inc	VET	109.261	53.950	5,895	0.4159%	4.78%	3.14%	0.0199%	0.0131%
CI Financial Corp	CIX	283.439	33.600	9,524	0.6720%	3.93%	12.69%	0.0264%	0.0853%
Yamana Gold Inc	YRI	941.575	3.760	3,540	0.2498%	1.97%	9.70%	0.0049%	0.0242%
Silver Wheaton Corp	SLW	404.098	21.650	8,749	0.6173%	1.11%	14.50%	0.0069%	0.0895%
Mitel Networks Corp	MNW	119.915	11.080	1,329	0.0000%	n/a	15.00%	n/a	0.0000%
WSP Global Inc	WSP	89.632	39.310	3,523	0.0000%	3.82%	n/a	0.0000%	n/a
Quebecor Inc	QBR/B	83.900	31.220	2,619	0.1848%	0.45%	6.87%	0.0008%	0.0127%
Intertape Polymer Group Inc	ITP	59.587	18.720	1,115	0.0000%	3.16%	n/a	0.0000%	n/a
Power Corp of Canada	POW	412.437	31.940	13,173	0.0000%	3.90%	n/a	0.0000%	n/a
Alamos Gold Inc	AGI	n/a	n/a	n/a	0.0000%	n/a	33.00%	n/a	0.0000%
Open Text Corp	OTC	122.224	50.730	6,200	0.0000%	1.97%	n/a	0.0000%	n/a
Canadian National Railway Co	CNR	802.701	72.060	57,843	4.0816%	1.73%	11.30%	0.0708%	0.4612%
Canadian Oil Sands Ltd	COS	484.614	10.100	4,895	0.3454%	1.98%	5.37%	0.0068%	0.0185%
IAMGOLD Corp	IMG	391.336	2.500	978	0.0000%	n/a	0.50%	n/a	0.0000%
Sierra Wireless Inc	SW	32.134	31.030	997	0.0000%	n/a	n/a	n/a	n/a
ARC Resources Ltd	ARX	340.028	21.400	7,277	0.5135%	5.61%	3.60%	0.0288%	0.0185%
Enerplus Corp	ERF	206.215	10.960	2,260	0.1595%	5.47%	-19.62%	0.0087%	-0.0313%
Raging River Exploration Inc	RRX	197.666	8.730	1,726	0.0000%	n/a	n/a	n/a	n/a
Average for Companies Paying Dividends with Long-Term Growth Estimates						**2.80%**	**13.15%**	**3.28%**	**10.02%**

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P., as of September 2, 2015
[6] Source: Bloomberg Finance L.P., as of September 2, 2015
[7] Equals Column [5] x Column [6]

[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and Best Long-Term Growth Estimate does not equal "n/a" and is greater than 0%
[9] Source: Bloomberg Finance L.P., as of September 2, 2015
[10] Source: Bloomberg Finance L.P., as of September 2, 2015
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield plus Average Daily Spread between 10-year and 30-year government bonds August 2015
[14] Equals Column [4] - (Column [13]/100)

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Alcoa Inc	AA	1,309.818	9.450	12,378	0.0804%	1.27%	5.00%	0.0010%	0.0040%
LyondellBasell Industries NV	LYB	465.875	85.380	39,776	0.2583%	3.65%	5.67%	0.0094%	0.0146%
American Express Co	AXP	1,001.283	76.720	76,818	0.4988%	1.51%	9.62%	0.0075%	0.0480%
Verizon Communications Inc	VZ	4,065.691	46.010	187,062	1.2146%	4.78%	7.42%	0.0581%	0.0902%
Avago Technologies Ltd	AVGO	259.730	125.970	32,718	0.2124%	1.27%	21.18%	0.0027%	0.0450%
Boeing Co/The	BA	679.495	130.680	88,796	0.5765%	2.79%	11.28%	0.0161%	0.0651%
Caterpillar Inc	CAT	602.633	76.440	46,065	0.2991%	4.03%	9.00%	0.0121%	0.0269%
JPMorgan Chase & Co	JPM	3,698.100	64.100	237,048	1.5391%	2.75%	6.70%	0.0423%	0.1031%
Chevron Corp	CVX	1,881.735	80.990	152,402	0.9895%	5.28%	-2.02%	0.0523%	-0.0200%
Coca-Cola Co/The	KO	4,350.004	39.320	171,042	1.1105%	3.36%	6.40%	0.0373%	0.0710%
AbbVie Inc	ABBV	1,655.276	62.410	103,306	0.6707%	3.27%	8.55%	0.0219%	0.0573%
Walt Disney Co/The	DIS	1,687.858	101.880	171,959	1.1165%	1.30%	11.43%	0.0145%	0.1276%
EI du Pont de Nemours & Co	DD	904.838	51.500	46,599	0.3026%	2.95%	3.40%	0.0089%	0.0103%
Exxon Mobil Corp	XOM	4,169.449	75.240	313,709	2.0368%	3.88%	11.36%	0.0790%	0.2313%
Phillips 66	PSX	537.660	79.070	42,513	0.2760%	2.83%	3.54%	0.0078%	0.0098%
General Electric Co	GE	10,096.429	24.820	250,593	1.6270%	3.71%	7.92%	0.0603%	0.1289%
Hewlett-Packard Co	HPQ	1,806.415	28.060	50,688	0.3291%	2.51%	4.01%	0.0083%	0.0132%
Home Depot Inc/The	HD	1,284.103	116.460	149,547	0.9710%	2.03%	13.64%	0.0197%	0.1324%
International Business Machines Corp	IBM	979.530	147.890	144,863	0.9406%	3.52%	6.65%	0.0331%	0.0625%
Johnson & Johnson	JNJ	2,769.106	93.980	260,241	1.6897%	3.19%	5.97%	0.0539%	0.1009%
McDonald's Corp	MCD	941.810	95.020	89,491	0.5810%	3.58%	7.89%	0.0208%	0.0459%
Merck & Co Inc	MRK	2,816.635	53.850	151,676	0.9848%	3.34%	6.33%	0.0329%	0.0624%
3M Co	MMM	624.745	142.140	88,801	0.5766%	2.88%	8.90%	0.0166%	0.0513%
Bank of America Corp	BAC	10,438.420	16.340	170,564	1.1074%	1.22%	6.65%	0.0136%	0.0736%
Pfizer Inc	PFE	6,167.348	32.220	198,712	1.2902%	3.48%	2.05%	0.0448%	0.0264%
Procter & Gamble Co/The	PG	2,713.146	70.670	191,738	1.2449%	3.75%	6.70%	0.0467%	0.0834%
AT&T Inc	T	6,151.000	33.200	204,213	1.3259%	5.66%	3.72%	0.0751%	0.0493%
Travelers Cos Inc/The	TRV	311.206	99.550	30,981	0.2011%	2.45%	8.62%	0.0049%	0.0173%
United Technologies Corp	UTX	890.598	91.610	81,588	0.5297%	2.79%	8.71%	0.0148%	0.0461%
Analog Devices Inc	ADI	313.675	55.860	17,522	0.1138%	2.86%	11.38%	0.0033%	0.0129%
Wal-Mart Stores Inc	WMT	3,220.549	64.730	208,466	1.3535%	3.03%	5.23%	0.0410%	0.0708%
Cisco Systems Inc	CSCO	5,085.889	25.880	131,623	0.8546%	3.25%	8.36%	0.0277%	0.0714%
Intel Corp	INTC	4,754.000	28.540	135,679	0.8809%	3.36%	7.99%	0.0296%	0.0704%
General Motors Co	GM	1,583.997	29.440	46,633	0.3028%	4.89%	11.86%	0.0148%	0.0359%
Microsoft Corp	MSFT	7,997.981	43.520	348,072	2.2599%	2.85%	10.47%	0.0644%	0.2366%
Dollar General Corp	DG	294.660	74.490	21,949	0.1425%	1.18%	11.85%	0.0017%	0.0169%
Kinder Morgan Inc/DE	KMI	2,191.937	32.410	71,041	0.4612%	6.05%	9.33%	0.0279%	0.0430%
Citigroup Inc	C	3,009.845	53.480	160,967	1.0451%	0.37%	20.61%	0.0039%	0.2154%
American International Group Inc	AIG	1,293.887	60.340	78,073	0.5069%	1.86%	9.04%	0.0094%	0.0458%
Honeywell International Inc	HON	781.762	99.270	77,606	0.5039%	2.09%	9.51%	0.0105%	0.0479%
Altria Group Inc	MO	1,960.695	53.580	105,054	0.6821%	4.22%	7.59%	0.0288%	0.0518%
HCA Holdings Inc	HCA	415.192	86.620	35,964	0.0000%	n/a	10.75%	n/a	0.0000%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

		[1]	[2]	[3]	[4]			[13]	[14]
		Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return			Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500		**2.58%**	**2.71%**	**9.66%**	**12.37%**			4.29	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Under Armour Inc	UA	179.962	95.530	17,192	0.0000%	n/a	22.75%	n/a	0.0000%
International Paper Co	IP	417.741	43.140	18,021	0.1170%	3.71%	8.28%	0.0043%	0.0097%
Abbott Laboratories	ABT	1,490.441	45.290	67,502	0.4383%	2.12%	12.28%	0.0093%	0.0538%
Aflac Inc	AFL	430.694	58.600	25,239	0.1639%	2.66%	8.79%	0.0044%	0.0144%
Air Products & Chemicals Inc	APD	214.982	139.530	29,996	0.1948%	2.32%	9.10%	0.0045%	0.0177%
Airgas Inc	ARG	74.654	96.520	7,206	0.0468%	2.49%	9.08%	0.0012%	0.0042%
Royal Caribbean Cruises Ltd	RCL	219.944	88.160	19,390	0.1259%	1.36%	20.54%	0.0017%	0.0259%
American Electric Power Co Inc	AEP	490.560	54.290	26,633	0.1729%	3.91%	5.10%	0.0068%	0.0088%
Hess Corp	HES	287.058	59.450	17,066	0.1108%	1.68%	-3.78%	0.0019%	-0.0042%
Anadarko Petroleum Corp	APC	508.012	71.580	36,363	0.2361%	1.51%	8.33%	0.0036%	0.0197%
Aon PLC	AON	280.043	93.440	26,167	0.1699%	1.28%	11.04%	0.0022%	0.0188%
Apache Corp	APA	377.987	45.240	17,100	0.1110%	2.21%	8.50%	0.0025%	0.0094%
Archer-Daniels-Midland Co	ADM	608.940	44.990	27,396	0.1779%	2.49%	4.21%	0.0044%	0.0075%
AGL Resources Inc	GAS	120.088	60.990	7,324	0.0476%	3.34%	6.50%	0.0016%	0.0031%
Automatic Data Processing Inc	ADP	465.810	77.320	36,016	0.2338%	2.53%	10.40%	0.0059%	0.0243%
AutoZone Inc	AZO	30.872	715.990	22,104	0.0000%	n/a	13.79%	n/a	0.0000%
Avery Dennison Corp	AVY	91.438	58.080	5,311	0.0345%	2.55%	7.35%	0.0009%	0.0025%
Baker Hughes Inc	BHI	435.882	56.000	24,409	0.1585%	1.21%	8.15%	0.0019%	0.0129%
Ball Corp	BLL	137.328	65.910	9,051	0.0588%	0.79%	9.07%	0.0005%	0.0053%
Bank of New York Mellon Corp/The	BK	1,106.518	39.800	44,039	0.2859%	1.71%	12.10%	0.0049%	0.0346%
CR Bard Inc	BCR	74.199	193.790	14,379	0.0934%	0.50%	10.00%	0.0005%	0.0093%
Baxter International Inc	BAX	545.539	38.450	20,976	0.1362%	1.20%	5.62%	0.0016%	0.0076%
Becton Dickinson and Co	BDX	210.254	141.020	29,650	0.1925%	1.70%	11.09%	0.0033%	0.0213%
Berkshire Hathaway Inc	BRK/B	1,247.366	134.040	167,197	0.0000%	n/a	5.80%	n/a	0.0000%
Best Buy Co Inc	BBY	352.771	36.740	12,961	0.0842%	2.50%	10.69%	0.0021%	0.0090%
H&R Block Inc	HRB	276.285	34.020	9,399	0.0610%	2.35%	11.00%	0.0014%	0.0067%
Boston Scientific Corp	BSX	1,343.957	16.740	22,498	0.0000%	n/a	9.72%	n/a	0.0000%
Bristol-Myers Squibb Co	BMY	1,667.503	59.470	99,166	0.6439%	2.49%	13.58%	0.0160%	0.0875%
Brown-Forman Corp	BF/B	121.963	98.100	11,965	0.0777%	1.28%	8.80%	0.0010%	0.0068%
Cabot Oil & Gas Corp	COG	413.808	23.670	9,795	0.0636%	0.34%	42.75%	0.0002%	0.0272%
Campbell Soup Co	CPB	310.521	47.990	14,902	0.0968%	2.60%	3.64%	0.0025%	0.0035%
Kansas City Southern	KSU	110.360	92.740	10,235	0.0665%	1.42%	11.38%	0.0009%	0.0076%
Carnival Corp	CCL	593.457	49.230	29,216	0.1897%	2.44%	17.12%	0.0046%	0.0325%
Qorvo Inc	QRVO	149.531	55.510	8,300	0.0000%	n/a	16.84%	n/a	0.0000%
CenturyLink Inc	CTL	562.986	27.040	15,223	0.0988%	7.99%	-1.74%	0.0079%	-0.0017%
Chubb Corp/The	CB	226.977	120.810	27,421	0.1780%	1.89%	7.73%	0.0034%	0.0138%
Cigna Corp	CI	257.495	140.790	36,253	0.2354%	0.03%	11.36%	0.0001%	0.0267%
Frontier Communications Corp	FTR	1,168.207	5.070	5,923	0.0385%	8.28%	3.00%	0.0032%	0.0012%
Clorox Co/The	CLX	128.644	111.170	14,301	0.0929%	2.77%	7.05%	0.0026%	0.0065%
CMS Energy Corp	CMS	276.668	32.780	9,069	0.0589%	3.54%	6.03%	0.0021%	0.0036%
Coca-Cola Enterprises Inc	CCE	229.086	51.490	11,796	0.0766%	2.18%	6.19%	0.0017%	0.0047%
Colgate-Palmolive Co	CL	900.132	62.810	56,537	0.3671%	2.42%	8.41%	0.0089%	0.0309%
Comerica Inc	CMA	177.929	44.000	7,829	0.0508%	1.91%	9.41%	0.0010%	0.0048%
CA Inc	CA	441.305	27.290	12,043	0.0782%	3.66%	5.70%	0.0029%	0.0045%
Computer Sciences Corp	CSC	138.332	61.990	8,575	0.0557%	1.48%	9.30%	0.0008%	0.0052%
ConAgra Foods Inc	CAG	431.735	41.680	17,995	0.1168%	2.40%	-3.05%	0.0028%	-0.0036%
Consolidated Edison Inc	ED	292.872	62.910	18,425	0.1196%	4.13%	3.33%	0.0049%	0.0040%
SL Green Realty Corp	SLG	99.707	103.510	10,321	0.0670%	2.32%	5.78%	0.0016%	0.0039%
Corning Inc	GLW	1,225.935	17.210	21,098	0.1370%	2.79%	1.28%	0.0038%	0.0018%
CSX Corp	CSX	983.737	27.380	26,935	0.1749%	2.63%	9.53%	0.0046%	0.0167%
Cummins Inc	CMI	178.650	121.750	21,751	0.1412%	3.20%	9.99%	0.0045%	0.0141%
Danaher Corp	DHR	683.488	87.020	59,477	0.3862%	0.62%	12.73%	0.0024%	0.0491%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Target Corp	TGT	628.430	77.710	48,835	0.3171%	2.88%	9.25%	0.0091%	0.0293%
Deere & Co	DE	328.166	81.780	26,837	0.1742%	2.93%	5.27%	0.0051%	0.0092%
Dominion Resources Inc/VA	D	594.322	69.750	41,454	0.2692%	3.71%	6.40%	0.0100%	0.0172%
Dover Corp	DOV	156.465	61.950	9,693	0.0629%	2.71%	12.00%	0.0017%	0.0076%
Dow Chemical Co/The	DOW	1,158.102	43.760	50,679	0.3290%	3.84%	6.93%	0.0126%	0.0228%
Duke Energy Corp	DUK	688.330	70.910	48,809	0.3169%	4.65%	4.84%	0.0147%	0.0153%
Eaton Corp PLC	ETN	467.500	57.060	26,676	0.1732%	3.86%	8.51%	0.0067%	0.0147%
Ecolab Inc	ECL	295.092	109.140	32,206	0.2091%	1.21%	13.17%	0.0025%	0.0275%
PerkinElmer Inc	PKI	113.383	48.680	5,519	0.0358%	0.58%	8.54%	0.0002%	0.0031%
EMC Corp/MA	EMC	1,924.726	24.870	47,868	0.3108%	1.85%	10.66%	0.0057%	0.0331%
Emerson Electric Co	EMR	657.140	47.720	31,359	0.2036%	3.94%	5.83%	0.0080%	0.0119%
EOG Resources Inc	EOG	549.171	78.310	43,006	0.2792%	0.86%	-4.17%	0.0024%	-0.0116%
Entergy Corp	ETR	179.528	65.330	11,729	0.0762%	5.08%	4.73%	0.0039%	0.0036%
Equifax Inc	EFX	118.244	97.900	11,576	0.0752%	1.18%	12.67%	0.0009%	0.0095%
EQT Corp	EQT	152.404	77.820	11,860	0.0770%	0.15%	25.00%	0.0001%	0.0193%
XL Group PLC	XL	302.314	37.290	11,273	0.0732%	2.15%	9.50%	0.0016%	0.0070%
FedEx Corp	FDX	282.501	150.610	42,547	0.2763%	0.66%	14.80%	0.0018%	0.0409%
Macy's Inc	M	330.983	58.610	19,399	0.1260%	2.46%	8.78%	0.0031%	0.0111%
FMC Corp	FMC	133.615	42.310	5,653	0.0367%	1.56%	6.75%	0.0006%	0.0025%
Ford Motor Co	F	3,896.986	13.870	54,051	0.3509%	4.33%	15.44%	0.0152%	0.0542%
NextEra Energy Inc	NEE	452.104	98.410	44,492	0.2889%	3.13%	6.01%	0.0090%	0.0174%
Franklin Resources Inc	BEN	613.818	40.580	24,909	0.1617%	1.48%	8.87%	0.0024%	0.0143%
Freeport-McMoRan Inc	FCX	1,040.228	10.640	11,068	0.0719%	1.88%	-16.19%	0.0014%	-0.0116%
TEGNA Inc	TGNA	226.472	23.790	5,388	0.0350%	2.35%	4.08%	0.0008%	0.0014%
Gap Inc/The	GPS	417.355	32.810	13,693	0.0889%	2.80%	10.60%	0.0025%	0.0094%
General Dynamics Corp	GD	322.727	142.030	45,837	0.2976%	1.94%	10.64%	0.0058%	0.0317%
General Mills Inc	GIS	598.738	56.760	33,984	0.2207%	3.10%	7.25%	0.0068%	0.0160%
Genuine Parts Co	GPC	151.597	83.490	12,657	0.0822%	2.95%	9.17%	0.0024%	0.0075%
WW Grainger Inc	GWW	65.975	223.440	14,741	0.0957%	2.09%	11.87%	0.0020%	0.0114%
Halliburton Co	HAL	854.749	39.350	33,634	0.2184%	1.83%	12.60%	0.0040%	0.0275%
Harley-Davidson Inc	HOG	205.967	56.050	11,544	0.0750%	2.21%	11.33%	0.0017%	0.0085%
Harman International Industries Inc	HAR	71.172	97.740	6,956	0.0452%	1.43%	17.00%	0.0006%	0.0077%
Joy Global Inc	JOY	97.454	24.220	2,360	0.0153%	3.30%	13.60%	0.0005%	0.0021%
Harris Corp	HRS	123.592	76.820	9,494	0.0000%	2.60%	n/a	0.0000%	n/a
HCP Inc	HCP	462.587	37.060	17,143	0.1113%	6.10%	3.02%	0.0068%	0.0034%
Helmerich & Payne Inc	HP	107.751	59.010	6,358	0.0413%	4.66%	27.51%	0.0019%	0.0114%
Hershey Co/The	HSY	158.765	89.520	14,213	0.0923%	2.61%	8.20%	0.0024%	0.0076%
Hormel Foods Corp	HRL	264.275	61.100	16,147	0.1048%	1.64%	6.60%	0.0017%	0.0069%
Starwood Hotels & Resorts Worldwide Inc	HOT	170.379	71.470	12,177	0.0791%	2.10%	9.55%	0.0017%	0.0076%
Mondelez International Inc	MDLZ	1,611.307	42.360	68,255	0.4432%	1.61%	10.86%	0.0071%	0.0481%
CenterPoint Energy Inc	CNP	430.262	18.620	8,011	0.0520%	5.32%	4.25%	0.0028%	0.0022%
Humana Inc	HUM	148.215	182.790	27,092	0.1759%	0.63%	12.55%	0.0011%	0.0221%
Illinois Tool Works Inc	ITW	366.089	84.530	30,946	0.2009%	2.60%	9.08%	0.0052%	0.0182%
Ingersoll-Rand PLC	IR	265.353	55.290	14,671	0.0953%	2.10%	10.22%	0.0020%	0.0097%
Interpublic Group of Cos Inc/The	IPG	410.401	18.880	7,748	0.0503%	2.54%	3.90%	0.0013%	0.0020%
International Flavors & Fragrances Inc	IFF	80.586	109.550	8,828	0.0573%	2.04%	9.20%	0.0012%	0.0053%
Jacobs Engineering Group Inc	JEC	123.799	40.410	5,003	0.0000%	n/a	8.42%	n/a	0.0000%
Johnson Controls Inc	JCI	654.069	41.140	26,908	0.1747%	2.53%	10.50%	0.0044%	0.0183%
Hanesbrands Inc	HBI	402.477	30.110	12,119	0.0787%	1.33%	11.25%	0.0010%	0.0089%
Kellogg Co	K	353.581	66.280	23,435	0.1522%	3.02%	5.07%	0.0046%	0.0077%
Perrigo Co PLC	PRGO	146.279	182.970	26,765	0.1738%	0.27%	12.29%	0.0005%	0.0214%
Kimberly-Clark Corp	KMB	364.275	106.530	38,806	0.2520%	3.30%	7.68%	0.0083%	0.0193%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Kimco Realty Corp	KIM	413.135	23.050	9,523	0.0618%	4.16%	4.69%	0.0026%	0.0029%
Kohl's Corp	KSS	197.876	51.030	10,098	0.0656%	3.53%	8.28%	0.0023%	0.0054%
Oracle Corp	ORCL	4,336.077	37.090	160,825	1.0442%	1.62%	7.89%	0.0169%	0.0824%
Kroger Co/The	KR	971.423	34.500	33,514	0.2176%	1.22%	10.42%	0.0026%	0.0227%
Legg Mason Inc	LM	109.708	44.330	4,863	0.0316%	1.80%	15.50%	0.0006%	0.0049%
Leggett & Platt Inc	LEG	136.829	44.420	6,078	0.0000%	2.88%	n/a	0.0000%	n/a
Lennar Corp	LEN	173.937	50.900	8,853	0.0575%	0.31%	20.20%	0.0002%	0.0116%
Leucadia National Corp	LUK	366.603	21.460	7,867	0.0000%	1.17%	n/a	0.0000%	n/a
Eli Lilly & Co	LLY	1,108.541	82.350	91,288	0.5927%	2.43%	10.45%	0.0144%	0.0619%
L Brands Inc	LB	291.964	83.900	24,496	0.1590%	2.38%	10.50%	0.0038%	0.0167%
Lincoln National Corp	LNC	250.952	50.790	12,746	0.0828%	1.58%	10.06%	0.0013%	0.0083%
Loews Corp	L	363.082	36.450	13,234	0.0000%	0.69%	n/a	0.0000%	n/a
Lowe's Cos Inc	LOW	932.686	69.170	64,514	0.4189%	1.62%	16.67%	0.0068%	0.0698%
Host Hotels & Resorts Inc	HST	751.123	17.730	13,317	0.0865%	4.51%	5.00%	0.0039%	0.0043%
Marsh & McLennan Cos Inc	MMC	529.993	53.730	28,477	0.1849%	2.31%	11.53%	0.0043%	0.0213%
Masco Corp	MAS	343.950	26.230	9,022	0.0586%	1.37%	15.39%	0.0008%	0.0090%
Mattel Inc	MAT	338.613	23.430	7,934	0.0515%	6.49%	9.65%	0.0033%	0.0050%
McGraw Hill Financial Inc	MHFI	272.500	96.990	26,430	0.1716%	1.36%	11.83%	0.0023%	0.0203%
Medtronic PLC	MDT	1,414.189	72.290	102,232	0.6638%	2.10%	9.10%	0.0140%	0.0604%
CVS Health Corp	CVS	1,114.486	102.400	114,123	0.7410%	1.37%	14.68%	0.0101%	0.1088%
Micron Technology Inc	MU	1,083.436	16.410	17,779	0.0000%	n/a	6.49%	n/a	0.0000%
Motorola Solutions Inc	MSI	206.777	64.820	13,403	0.0870%	2.10%	8.80%	0.0018%	0.0077%
Murphy Oil Corp	MUR	172.752	31.000	5,355	0.0348%	4.52%	13.00%	0.0016%	0.0045%
Mylan NV	MYL	491.554	49.590	24,376	0.0000%	n/a	11.00%	n/a	0.0000%
Laboratory Corp of America Holdings	LH	101.100	117.810	11,911	0.0000%	n/a	10.27%	n/a	0.0000%
Tenet Healthcare Corp	THC	99.564	49.230	4,902	0.0000%	n/a	12.33%	n/a	0.0000%
Newell Rubbermaid Inc	NWL	267.800	42.130	11,282	0.0733%	1.80%	9.52%	0.0013%	0.0070%
Newmont Mining Corp	NEM	529.055	17.070	9,031	0.0586%	0.59%	2.10%	0.0003%	0.0012%
Twenty-First Century Fox Inc	FOXA	1,220.940	27.390	33,442	0.2171%	1.10%	15.58%	0.0024%	0.0338%
NIKE Inc	NKE	677.926	111.750	75,758	0.4919%	1.00%	11.21%	0.0049%	0.0552%
NiSource Inc	NI	317.859	16.790	5,337	0.0347%	3.69%	-0.30%	0.0013%	-0.0001%
Noble Energy Inc	NBL	428.034	33.410	14,301	0.0929%	2.16%	3.53%	0.0020%	0.0033%
Norfolk Southern Corp	NSC	301.387	77.910	23,481	0.1525%	3.03%	9.37%	0.0046%	0.0143%
Eversource Energy	ES	317.173	47.240	14,983	0.0973%	3.54%	6.50%	0.0034%	0.0063%
Northrop Grumman Corp	NOC	187.393	163.740	30,684	0.1992%	1.95%	6.57%	0.0039%	0.0131%
Wells Fargo & Co	WFC	5,133.359	53.330	273,762	1.7775%	2.81%	11.71%	0.0500%	0.2081%
Nucor Corp	NUE	319.600	43.290	13,835	0.0898%	3.44%	12.43%	0.0031%	0.0112%
PVH Corp	PVH	82.692	118.980	9,839	0.0639%	0.13%	9.61%	0.0001%	0.0061%
Occidental Petroleum Corp	OXY	763.951	73.010	55,776	0.3621%	4.11%	7.00%	0.0149%	0.0253%
Omnicom Group Inc	OMC	242.948	66.980	16,273	0.1057%	2.99%	5.33%	0.0032%	0.0056%
ONEOK Inc	OKE	209.167	36.010	7,532	0.0489%	6.72%	9.63%	0.0033%	0.0047%
Owens-Illinois Inc	OI	160.768	20.850	3,352	0.0000%	n/a	2.37%	n/a	0.0000%
PG&E Corp	PCG	489.166	49.580	24,253	0.1575%	3.67%	6.00%	0.0058%	0.0094%
Parker-Hannifin Corp	PH	138.419	107.660	14,902	0.0968%	2.34%	8.95%	0.0023%	0.0087%
PPL Corp	PPL	669.970	30.990	20,762	0.1348%	4.87%	2.85%	0.0066%	0.0038%
PepsiCo Inc	PEP	1,468.993	92.930	136,514	0.8863%	3.02%	5.96%	0.0268%	0.0528%
Exelon Corp	EXC	861.618	30.760	26,503	0.1721%	4.03%	6.69%	0.0069%	0.0115%
ConocoPhillips	COP	1,233.459	49.150	60,625	0.3936%	6.02%	1.82%	0.0237%	0.0072%
PulteGroup Inc	PHM	352.790	20.690	7,299	0.0474%	1.55%	14.00%	0.0007%	0.0066%
Pinnacle West Capital Corp	PNW	110.814	59.530	6,597	0.0428%	4.00%	5.54%	0.0017%	0.0024%
Pitney Bowes Inc	PBI	201.919	19.810	4,000	0.0260%	3.79%	14.00%	0.0010%	0.0036%
Plum Creek Timber Co Inc	PCL	174.729	38.490	6,725	0.0437%	4.57%	11.45%	0.0020%	0.0050%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
PNC Financial Services Group Inc/The	PNC	513.600	91.120	46,799	0.3039%	2.24%	7.80%	0.0068%	0.0237%
PPG Industries Inc	PPG	270.721	95.290	25,797	0.1675%	1.51%	7.10%	0.0025%	0.0119%
Praxair Inc	PX	286.472	105.750	30,294	0.1967%	2.70%	9.00%	0.0053%	0.0177%
Precision Castparts Corp	PCP	137.498	230.250	31,659	0.2056%	0.05%	10.56%	0.0001%	0.0217%
Progressive Corp/The	PGR	585.932	29.960	17,555	0.1140%	2.29%	7.92%	0.0026%	0.0090%
Public Service Enterprise Group Inc	PEG	505.875	40.250	20,361	0.1322%	3.88%	5.67%	0.0051%	0.0075%
Raytheon Co	RTN	303.548	102.560	31,132	0.2021%	2.61%	8.35%	0.0053%	0.0169%
Robert Half International Inc	RHI	134.500	51.030	6,864	0.0446%	1.57%	14.10%	0.0007%	0.0063%
Ryder System Inc	R	53.374	81.970	4,375	0.0284%	2.00%	12.75%	0.0006%	0.0036%
SCANA Corp	SCG	142.917	52.890	7,559	0.0491%	4.12%	5.90%	0.0020%	0.0029%
Edison International	EIX	325.811	58.480	19,053	0.1237%	2.86%	5.68%	0.0035%	0.0070%
Schlumberger Ltd	SLB	1,265.449	77.370	97,908	0.6357%	2.59%	10.12%	0.0164%	0.0643%
Charles Schwab Corp/The	SCHW	1,315.624	30.380	39,969	0.2595%	0.79%	22.39%	0.0021%	0.0581%
Sherwin-Williams Co/The	SHW	93.211	255.810	23,844	0.1548%	1.05%	19.65%	0.0016%	0.0304%
JM Smucker Co/The	SJM	119.667	117.720	14,087	0.0915%	2.28%	8.83%	0.0021%	0.0081%
Snap-on Inc	SNA	58.172	159.770	9,294	0.0603%	1.33%	3.90%	0.0008%	0.0024%
AMETEK Inc	AME	242.164	53.820	13,033	0.0846%	0.67%	10.84%	0.0006%	0.0092%
Southern Co/The	SO	908.425	43.410	39,435	0.2560%	5.00%	4.16%	0.0128%	0.0107%
BB&T Corp	BBT	779.607	36.920	28,783	0.1869%	2.93%	8.37%	0.0055%	0.0156%
Southwest Airlines Co	LUV	659.356	36.700	24,198	0.1571%	0.82%	18.02%	0.0013%	0.0283%
Southwestern Energy Co	SWN	384.488	16.240	6,244	0.0000%	n/a	9.29%	n/a	0.0000%
Stanley Black & Decker Inc	SWK	153.239	101.520	15,557	0.1010%	2.17%	10.67%	0.0022%	0.0108%
Public Storage	PSA	172.967	201.270	34,813	0.2260%	3.38%	4.60%	0.0076%	0.0104%
SunTrust Banks Inc	STI	514.047	40.370	20,752	0.1347%	2.38%	6.59%	0.0032%	0.0089%
Sysco Corp	SYY	586.766	39.870	23,394	0.1519%	3.01%	8.25%	0.0046%	0.0125%
TECO Energy Inc	TE	235.216	21.070	4,956	0.0322%	4.27%	5.00%	0.0014%	0.0016%
Tesoro Corp	TSO	123.097	92.010	11,326	0.0735%	2.17%	16.42%	0.0016%	0.0121%
Texas Instruments Inc	TXN	1,026.386	47.840	49,102	0.3188%	2.84%	9.23%	0.0091%	0.0294%
Textron Inc	TXT	276.422	38.800	10,725	0.0696%	0.21%	9.26%	0.0001%	0.0064%
Thermo Fisher Scientific Inc	TMO	398.488	125.370	49,958	0.3244%	0.48%	11.30%	0.0016%	0.0367%
Tiffany & Co	TIF	128.947	82.250	10,606	0.0689%	1.95%	11.57%	0.0013%	0.0080%
TJX Cos Inc/The	TJX	674.371	70.320	47,422	0.3079%	1.19%	10.92%	0.0037%	0.0336%
Torchmark Corp	TMK	125.115	58.460	7,314	0.0475%	0.92%	8.04%	0.0004%	0.0038%
Total System Services Inc	TSS	183.950	45.830	8,430	0.0547%	0.87%	11.75%	0.0005%	0.0064%
Tyco International Plc	TYC	421.516	36.290	15,297	0.0993%	2.26%	11.03%	0.0022%	0.0110%
Union Pacific Corp	UNP	867.692	85.740	74,396	0.4830%	2.57%	9.03%	0.0124%	0.0436%
UnitedHealth Group Inc	UNH	953.563	115.700	110,327	0.7163%	1.73%	12.53%	0.0124%	0.0897%
Unum Group	UNM	246.681	33.540	8,274	0.0537%	2.21%	8.50%	0.0012%	0.0046%
Marathon Oil Corp	MRO	677.185	17.290	11,709	0.0760%	4.86%	-20.11%	0.0037%	-0.0153%
Varian Medical Systems Inc	VAR	98.717	81.250	8,021	0.0000%	n/a	12.75%	n/a	0.0000%
Ventas Inc	VTR	332.502	55.020	18,294	0.1188%	5.74%	2.89%	0.0068%	0.0034%
VF Corp	VFC	425.642	72.430	30,829	0.2002%	1.77%	12.12%	0.0035%	0.0243%
Vornado Realty Trust	VNO	188.497	87.190	16,435	0.1067%	2.89%	6.26%	0.0031%	0.0067%
ADT Corp/The	ADT	169.933	32.780	5,570	0.0362%	2.56%	6.33%	0.0009%	0.0023%
Vulcan Materials Co	VMC	133.186	93.620	12,469	0.0810%	0.43%	41.23%	0.0003%	0.0334%
Weyerhaeuser Co	WY	514.194	27.940	14,367	0.0933%	4.44%	3.50%	0.0041%	0.0033%
Whirlpool Corp	WHR	78.418	168.100	13,182	0.0856%	2.14%	19.24%	0.0018%	0.0165%
Williams Cos Inc/The	WMB	749.711	48.200	36,136	0.2346%	4.90%	3.75%	0.0115%	0.0088%
WEC Energy Group Inc	WEC	315.684	47.650	15,042	0.0977%	1.96%	4.07%	0.0019%	0.0040%
Xerox Corp	XRX	1,068.795	10.170	10,870	0.0706%	2.75%	9.00%	0.0019%	0.0064%
Adobe Systems Inc	ADBE	497.645	78.570	39,100	0.0000%	n/a	16.25%	n/a	0.0000%
AES Corp/VA	AES	682.827	12.000	8,194	0.0532%	3.33%	5.20%	0.0018%	0.0028%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Amgen Inc	AMGN	758.250	151.780	115,087	0.7472%	2.08%	8.63%	0.0156%	0.0645%
Apple Inc	AAPL	5,702.722	112.760	643,039	4.1751%	1.84%	16.92%	0.0770%	0.7064%
Autodesk Inc	ADSK	226.199	46.750	10,575	0.0000%	n/a	13.74%	n/a	0.0000%
Cintas Corp	CTAS	110.211	84.990	9,367	0.0608%	1.00%	11.70%	0.0006%	0.0071%
Comcast Corp	CMCSA	2,114.785	56.330	119,126	0.7735%	1.78%	12.68%	0.0137%	0.0981%
Molson Coors Brewing Co	TAP	162.774	68.090	11,083	0.0720%	2.41%	1.55%	0.0017%	0.0011%
KLA-Tencor Corp	KLAC	157.531	50.110	7,894	0.0513%	4.15%	17.27%	0.0021%	0.0089%
Marriott International Inc/MD	MAR	265.888	70.660	18,788	0.1220%	1.42%	14.42%	0.0017%	0.0176%
McCormick & Co Inc/MD	MKC	115.965	79.280	9,194	0.0000%	2.02%	n/a	0.0000%	n/a
Nordstrom Inc	JWN	190.534	72.880	13,886	0.0902%	2.03%	10.12%	0.0018%	0.0091%
PACCAR Inc	PCAR	354.968	58.970	20,932	0.1359%	1.63%	7.70%	0.0022%	0.0105%
Costco Wholesale Corp	COST	439.488	140.050	61,550	0.3996%	1.14%	9.79%	0.0046%	0.0391%
Sigma-Aldrich Corp	SIAL	119.804	139.410	16,702	0.1084%	0.66%	5.13%	0.0007%	0.0056%
St Jude Medical Inc	STJ	281.745	70.810	19,950	0.1295%	1.64%	11.40%	0.0021%	0.0148%
Stryker Corp	SYK	376.558	98.650	37,147	0.2412%	1.40%	10.97%	0.0034%	0.0265%
Tyson Foods Inc	TSN	304.359	42.280	12,868	0.0836%	0.95%	6.00%	0.0008%	0.0050%
Altera Corp	ALTR	302.836	48.550	14,703	0.0955%	1.48%	12.27%	0.0014%	0.0117%
Applied Materials Inc	AMAT	1,200.619	16.085	19,312	0.1254%	2.49%	11.96%	0.0031%	0.0150%
Time Warner Inc	TWX	815.581	71.100	57,988	0.3765%	1.97%	15.14%	0.0074%	0.0570%
Bed Bath & Beyond Inc	BBBY	169.596	62.110	10,534	0.0000%	n/a	6.61%	n/a	0.0000%
American Airlines Group Inc	AAL	671.821	38.980	26,188	0.1700%	1.03%	17.78%	0.0017%	0.0302%
Cardinal Health Inc	CAH	327.359	82.270	26,932	0.1749%	1.88%	10.40%	0.0033%	0.0182%
Celgene Corp	CELG	790.540	118.080	93,347	0.0000%	n/a	23.83%	n/a	0.0000%
Cerner Corp	CERN	345.074	61.760	21,312	0.0000%	n/a	16.78%	n/a	0.0000%
Cincinnati Financial Corp	CINF	164.093	52.330	8,587	0.0000%	3.52%	n/a	0.0000%	n/a
Cablevision Systems Corp	CVC	222.337	25.170	5,596	0.0363%	2.38%	1.84%	0.0009%	0.0007%
DR Horton Inc	DHI	366.778	30.370	11,139	0.0723%	0.82%	21.50%	0.0006%	0.0155%
Flowserve Corp	FLS	133.368	45.130	6,019	0.0391%	1.60%	7.04%	0.0006%	0.0028%
Electronic Arts Inc	EA	311.746	66.150	20,622	0.0000%	n/a	11.68%	n/a	0.0000%
Express Scripts Holding Co	ESRX	675.731	83.600	56,491	0.0000%	n/a	12.12%	n/a	0.0000%
Expeditors International of Washington Inc	EXPD	189.160	48.970	9,263	0.0601%	1.47%	11.58%	0.0009%	0.0070%
Fastenal Co	FAST	290.165	38.540	11,183	0.0726%	2.91%	15.60%	0.0021%	0.0113%
M&T Bank Corp	MTB	133.238	118.240	15,754	0.1023%	2.37%	8.09%	0.0024%	0.0083%
Fiserv Inc	FISV	234.578	85.270	20,002	0.0000%	n/a	12.80%	n/a	0.0000%
Fifth Third Bancorp	FITB	809.290	19.920	16,121	0.1047%	2.61%	4.20%	0.0027%	0.0044%
Gilead Sciences Inc	GILD	1,467.606	105.070	154,201	1.0012%	1.64%	4.40%	0.0164%	0.0440%
Hasbro Inc	HAS	124.903	74.590	9,317	0.0605%	2.47%	10.20%	0.0015%	0.0062%
Huntington Bancshares Inc/OH	HBAN	803.066	10.910	8,761	0.0569%	2.20%	8.64%	0.0013%	0.0049%
Health Care REIT Inc	HCN	351.885	63.350	22,292	0.1447%	5.21%	4.55%	0.0075%	0.0066%
Biogen Inc	BIIB	235.169	297.300	69,916	0.0000%	n/a	14.45%	n/a	0.0000%
Linear Technology Corp	LLTC	239.758	40.280	9,657	0.0627%	2.98%	7.20%	0.0019%	0.0045%
Range Resources Corp	RRC	169.362	38.620	6,541	0.0425%	0.41%	10.45%	0.0002%	0.0044%
Northern Trust Corp	NTRS	232.853	69.840	16,262	0.1056%	2.06%	13.79%	0.0022%	0.0146%
Paychex Inc	PAYX	361.206	44.660	16,131	0.1047%	3.76%	9.89%	0.0039%	0.0104%
People's United Financial Inc	PBCT	309.993	15.500	4,805	0.0000%	4.32%	n/a	0.0000%	n/a
Patterson Cos Inc	PDCO	103.376	45.830	4,738	0.0308%	1.92%	8.62%	0.0006%	0.0027%
QUALCOMM Inc	QCOM	1,571.202	56.580	88,899	0.5772%	3.39%	10.80%	0.0196%	0.0623%
Roper Technologies Inc	ROP	100.666	162.090	16,317	0.1059%	0.62%	13.20%	0.0007%	0.0140%
Ross Stores Inc	ROST	411.357	48.620	20,000	0.1299%	0.97%	10.67%	0.0013%	0.0139%
AutoNation Inc	AN	113.441	59.840	6,788	0.0000%	n/a	13.16%	n/a	0.0000%
Starbucks Corp	SBUX	1,484.200	54.710	81,201	0.5272%	1.17%	18.35%	0.0062%	0.0967%
KeyCorp	KEY	840.861	13.740	11,553	0.0750%	2.18%	7.10%	0.0016%	0.0053%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
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Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Staples Inc	SPLS	643.566	14.210	9,145	0.0594%	3.38%	0.89%	0.0020%	0.0005%
State Street Corp	STT	408.113	71.920	29,351	0.1906%	1.89%	9.01%	0.0036%	0.0172%
US Bancorp	USB	1,761.004	42.350	74,579	0.4842%	2.41%	8.12%	0.0117%	0.0393%
Symantec Corp	SYMC	684.173	20.490	14,019	0.0910%	2.93%	8.35%	0.0027%	0.0076%
T Rowe Price Group Inc	TROW	256.213	71.880	18,417	0.1196%	2.89%	11.26%	0.0035%	0.0135%
Waste Management Inc	WM	452.250	50.060	22,640	0.1470%	3.08%	7.88%	0.0045%	0.0116%
CBS Corp	CBS	444.408	45.240	20,105	0.1305%	1.33%	15.02%	0.0017%	0.0196%
Allergan plc	AGN	393.636	303.740	119,563	0.0000%	n/a	12.35%	n/a	0.0000%
Whole Foods Market Inc	WFM	357.858	32.760	11,723	0.0761%	1.59%	12.30%	0.0012%	0.0094%
Constellation Brands Inc	STZ	171.987	128.000	22,014	0.1429%	0.97%	12.21%	0.0014%	0.0175%
Xilinx Inc	XLNX	258.658	41.890	10,835	0.0704%	2.96%	8.58%	0.0021%	0.0060%
DENTSPLY International Inc	XRAY	139.808	52.410	7,327	0.0476%	0.55%	9.36%	0.0003%	0.0045%
Zions Bancorporation	ZION	204.170	29.000	5,921	0.0384%	0.83%	8.47%	0.0003%	0.0033%
Invesco Ltd	IVZ	428.719	34.110	14,624	0.0949%	3.17%	11.21%	0.0030%	0.0106%
Intuit Inc	INTU	275.669	85.750	23,639	0.1535%	1.40%	17.06%	0.0021%	0.0262%
Morgan Stanley	MS	1,953.385	34.450	67,294	0.4369%	1.74%	11.93%	0.0076%	0.0521%
Microchip Technology Inc	MCHP	211.091	42.500	8,971	0.0582%	3.37%	4.60%	0.0020%	0.0027%
ACE Ltd	ACE	323.805	102.160	33,080	0.2148%	2.62%	8.16%	0.0056%	0.0175%
Chesapeake Energy Corp	CHK	665.367	7.810	5,197	0.0000%	n/a	7.98%	n/a	0.0000%
O'Reilly Automotive Inc	ORLY	99.403	240.070	23,864	0.0000%	n/a	18.05%	n/a	0.0000%
Allstate Corp/The	ALL	400.390	58.280	23,335	0.1515%	2.06%	9.70%	0.0031%	0.0147%
FLIR Systems Inc	FLIR	140.248	28.630	4,015	0.0261%	1.54%	13.50%	0.0004%	0.0035%
Equity Residential	EQR	364.082	71.250	25,941	0.1684%	3.10%	8.52%	0.0052%	0.0143%
BorgWarner Inc	BWA	226.315	43.640	9,876	0.0641%	1.19%	11.03%	0.0008%	0.0071%
Newfield Exploration Co	NFX	162.989	33.310	5,429	0.0000%	n/a	7.21%	n/a	0.0000%
Urban Outfitters Inc	URBN	125.126	30.860	3,861	0.0000%	n/a	15.79%	n/a	0.0000%
Simon Property Group Inc	SPG	309.410	179.320	55,483	0.3602%	3.46%	7.55%	0.0125%	0.0272%
Eastman Chemical Co	EMN	148.664	72.460	10,772	0.0699%	2.21%	7.17%	0.0015%	0.0050%
AvalonBay Communities Inc	AVB	132.902	165.060	21,937	0.1424%	3.03%	7.40%	0.0043%	0.0105%
Prudential Financial Inc	PRU	451.000	80.700	36,396	0.2363%	2.87%	15.78%	0.0068%	0.0373%
United Parcel Service Inc	UPS	698.448	97.650	68,203	0.4428%	2.99%	11.49%	0.0132%	0.0509%
Apartment Investment & Management Co	AIV	156.282	36.030	5,631	0.0366%	3.33%	7.21%	0.0012%	0.0026%
Walgreens Boots Alliance Inc	WBA	1,092.283	86.550	94,537	0.6138%	1.66%	14.00%	0.0102%	0.0859%
McKesson Corp	MCK	232.403	197.580	45,918	0.2981%	0.57%	10.80%	0.0017%	0.0322%
Lockheed Martin Corp	LMT	310.535	201.180	62,473	0.4056%	2.98%	8.13%	0.0121%	0.0330%
AmerisourceBergen Corp	ABC	216.202	100.040	21,629	0.1404%	1.16%	17.79%	0.0016%	0.0250%
Cameron International Corp	CAM	191.514	66.760	12,785	0.0000%	n/a	2.27%	n/a	0.0000%
Capital One Financial Corp	COF	542.429	77.750	42,174	0.2738%	2.06%	6.42%	0.0056%	0.0176%
Waters Corp	WAT	82.270	121.380	9,986	0.0000%	n/a	9.69%	n/a	0.0000%
Dollar Tree Inc	DLTR	234.637	76.260	17,893	0.0000%	n/a	15.00%	n/a	0.0000%
Darden Restaurants Inc	DRI	127.683	68.010	8,684	0.0564%	3.23%	12.11%	0.0018%	0.0068%
SanDisk Corp	SNDK	204.439	54.560	11,154	0.0724%	2.20%	0.38%	0.0016%	0.0003%
Diamond Offshore Drilling Inc	DO	137.159	23.710	3,252	0.0000%	2.11%	n/a	0.0000%	n/a
NetApp Inc	NTAP	300.083	31.960	9,591	0.0623%	2.25%	10.02%	0.0014%	0.0062%
Citrix Systems Inc	CTXS	160.701	68.110	10,945	0.0000%	n/a	14.38%	n/a	0.0000%
Goodyear Tire & Rubber Co/The	GT	269.399	29.770	8,020	0.0521%	0.81%	7.00%	0.0004%	0.0036%
DaVita HealthCare Partners Inc	DVA	215.500	75.640	16,300	0.0000%	n/a	10.26%	n/a	0.0000%
Hartford Financial Services Group Inc/The	HIG	414.845	45.950	19,062	0.1238%	1.83%	9.25%	0.0023%	0.0114%
Iron Mountain Inc	IRM	210.826	28.340	5,975	0.0388%	6.70%	4.60%	0.0026%	0.0018%
Estee Lauder Cos Inc/The	EL	225.861	79.770	18,017	0.1170%	1.20%	11.49%	0.0014%	0.0134%
Yahoo! Inc	YHOO	941.391	32.240	30,350	0.0000%	n/a	13.33%	n/a	0.0000%
Principal Financial Group Inc	PFG	294.745	50.350	14,840	0.0964%	3.02%	10.17%	0.0029%	0.0098%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
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S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

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Stericycle Inc	SRCL	84.833	141.140	11,973	0.0000%	n/a	15.37%	n/a	0.0000%
Universal Health Services Inc	UHS	91.736	137.140	12,581	0.0817%	0.29%	10.19%	0.0002%	0.0083%
E*TRADE Financial Corp	ETFC	290.307	26.290	7,632	0.0000%	n/a	17.42%	n/a	0.0000%
Skyworks Solutions Inc	SWKS	190.738	87.350	16,661	0.1082%	1.19%	21.08%	0.0013%	0.0228%
National Oilwell Varco Inc	NOV	383.809	42.330	16,247	0.1055%	4.35%	-14.01%	0.0046%	-0.0148%
Quest Diagnostics Inc	DGX	143.553	67.800	9,733	0.0632%	2.24%	11.30%	0.0014%	0.0071%
Activision Blizzard Inc	ATVI	729.020	28.630	20,872	0.1355%	0.80%	9.78%	0.0011%	0.0133%
Rockwell Automation Inc	ROK	134.106	111.830	14,997	0.0974%	2.33%	8.40%	0.0023%	0.0082%
Kraft Heinz Co/The	KHC	1,212.833	72.660	88,124	0.5722%	3.03%	12.30%	0.0173%	0.0704%
American Tower Corp	AMT	423.279	92.190	39,022	0.2534%	1.91%	14.48%	0.0048%	0.0367%
Regeneron Pharmaceuticals Inc	REGN	101.737	513.500	52,242	0.0000%	n/a	21.33%	n/a	0.0000%
Amazon.com Inc	AMZN	467.710	512.890	239,884	0.0000%	n/a	47.77%	n/a	0.0000%
Ralph Lauren Corp	RL	59.767	111.190	6,645	0.0431%	1.80%	11.09%	0.0008%	0.0048%
Boston Properties Inc	BXP	153.574	113.380	17,412	0.1131%	2.29%	6.35%	0.0026%	0.0072%
Amphenol Corp	APH	309.147	52.360	16,187	0.1051%	1.07%	6.69%	0.0011%	0.0070%
Pioneer Natural Resources Co	PXD	149.308	123.060	18,374	0.1193%	0.07%	8.73%	0.0001%	0.0104%
Valero Energy Corp	VLO	497.112	59.340	29,499	0.1915%	2.70%	-1.23%	0.0052%	-0.0023%
L-3 Communications Holdings Inc	LLL	80.332	105.470	8,473	0.0550%	2.47%	6.79%	0.0014%	0.0037%
Western Union Co/The	WU	511.432	18.440	9,431	0.0612%	3.36%	9.03%	0.0021%	0.0055%
CH Robinson Worldwide Inc	CHRW	141.801	67.430	9,562	0.0621%	2.25%	10.63%	0.0014%	0.0066%
Accenture PLC	ACN	624.135	94.270	58,837	0.3820%	2.16%	10.33%	0.0083%	0.0395%
Yum! Brands Inc	YUM	431.206	79.770	34,397	0.2233%	2.06%	11.82%	0.0046%	0.0264%
Prologis Inc	PLD	524.047	38.000	19,914	0.1293%	4.21%	4.99%	0.0054%	0.0064%
FirstEnergy Corp	FE	422.453	31.960	13,502	0.0877%	4.51%	-0.68%	0.0039%	-0.0006%
VeriSign Inc	VRSN	113.493	68.940	7,824	0.0000%	n/a	10.40%	n/a	0.0000%
Quanta Services Inc	PWR	196.832	24.240	4,771	0.0000%	n/a	7.45%	n/a	0.0000%
Ameren Corp	AEE	242.635	40.290	9,776	0.0635%	4.07%	6.77%	0.0026%	0.0043%
Henry Schein Inc	HSIC	83.397	136.810	11,410	0.0000%	n/a	11.12%	n/a	0.0000%
Broadcom Corp	BRCM	559.000	51.670	28,884	0.1875%	1.08%	12.24%	0.0020%	0.0230%
NVIDIA Corp	NVDA	539.000	22.480	12,117	0.0787%	1.73%	8.80%	0.0014%	0.0069%
Sealed Air Corp	SEE	205.842	51.450	10,591	0.0688%	1.01%	10.11%	0.0007%	0.0069%
Cognizant Technology Solutions Corp	CTSH	609.529	62.940	38,364	0.0000%	n/a	15.50%	n/a	0.0000%
Intuitive Surgical Inc	ISRG	37.019	510.950	18,915	0.0000%	n/a	15.36%	n/a	0.0000%
CONSOL Energy Inc	CNX	229.004	15.230	3,488	0.0226%	0.26%	12.40%	0.0001%	0.0028%
Aetna Inc	AET	348.688	114.520	39,932	0.2593%	0.87%	12.06%	0.0023%	0.0313%
Affiliated Managers Group Inc	AMG	54.284	186.440	10,121	0.0000%	n/a	14.71%	n/a	0.0000%
Republic Services Inc	RSG	348.917	40.980	14,299	0.0928%	2.93%	4.85%	0.0027%	0.0045%
eBay Inc	EBAY	1,218.228	27.110	33,026	0.0000%	n/a	9.71%	n/a	0.0000%
Goldman Sachs Group Inc/The	GS	432.871	188.600	81,639	0.5301%	1.38%	18.98%	0.0073%	0.1006%
Sempra Energy	SRE	247.580	94.850	23,483	0.1525%	2.95%	7.75%	0.0045%	0.0118%
Moody's Corp	MCO	200.300	102.310	20,493	0.1331%	1.33%	13.50%	0.0018%	0.0180%
Priceline Group Inc/The	PCLN	50.702	1,248.640	63,309	0.0000%	n/a	18.97%	n/a	0.0000%
F5 Networks Inc	FFIV	71.004	121.410	8,621	0.0000%	n/a	15.41%	n/a	0.0000%
Akamai Technologies Inc	AKAM	178.595	71.310	12,736	0.0000%	n/a	15.80%	n/a	0.0000%
Reynolds American Inc	RAI	714.551	83.750	59,844	0.3886%	3.44%	11.08%	0.0134%	0.0431%
Devon Energy Corp	DVN	411.000	42.660	17,533	0.1138%	2.25%	6.24%	0.0026%	0.0071%
Google Inc	GOOGL	289.886	647.820	187,794	0.0000%	n/a	17.33%	n/a	0.0000%
Red Hat Inc	RHT	183.483	72.210	13,249	0.0000%	n/a	17.86%	n/a	0.0000%
Hudson City Bancorp Inc	HCBK	529.529	9.300	4,925	0.0320%	1.72%	-3.00%	0.0006%	-0.0010%
Netflix Inc	NFLX	424.363	115.030	48,814	0.0000%	n/a	32.49%	n/a	0.0000%
Allegion PLC	ALLE	95.812	59.610	5,711	0.0371%	0.67%	14.70%	0.0002%	0.0055%
Agilent Technologies Inc	A	333.192	36.310	12,098	0.0786%	1.10%	5.90%	0.0009%	0.0046%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Anthem Inc	ANTM	261.587	141.050	36,897	0.2396%	1.77%	9.61%	0.0042%	0.0230%
CME Group Inc/IL	CME	337.756	94.440	31,898	0.2071%	2.12%	12.36%	0.0044%	0.0256%
Juniper Networks Inc	JNPR	384.427	25.710	9,884	0.0642%	1.56%	11.84%	0.0010%	0.0076%
BlackRock Inc	BLK	163.636	302.470	49,495	0.3214%	2.88%	14.62%	0.0093%	0.0470%
DTE Energy Co	DTE	179.330	78.060	13,998	0.0909%	3.74%	5.15%	0.0034%	0.0047%
NASDAQ OMX Group Inc/The	NDAQ	168.930	51.190	8,648	0.0561%	1.95%	6.88%	0.0011%	0.0039%
Philip Morris International Inc	PM	1,549.186	79.800	123,625	0.8027%	5.01%	5.87%	0.0402%	0.0471%
Time Warner Cable Inc	TWC	282.974	186.020	52,639	0.3418%	1.61%	9.75%	0.0055%	0.0333%
salesforce.com inc	CRM	660.000	69.360	45,778	0.0000%	n/a	25.57%	n/a	0.0000%
MetLife Inc	MET	1,116.881	50.100	55,956	0.3633%	2.99%	7.25%	0.0109%	0.0264%
Monsanto Co	MON	467.835	97.650	45,684	0.2966%	2.21%	10.90%	0.0066%	0.0323%
Coach Inc	COH	276.627	30.250	8,368	0.0543%	4.46%	10.88%	0.0024%	0.0059%
Fluor Corp	FLR	144.943	45.620	6,612	0.0429%	1.84%	2.49%	0.0008%	0.0011%
Dun & Bradstreet Corp/The	DNB	36.111	105.970	3,827	0.0248%	1.75%	10.15%	0.0004%	0.0025%
Edwards Lifesciences Corp	EW	107.516	140.880	15,147	0.0000%	n/a	15.20%	n/a	0.0000%
Ameriprise Financial Inc	AMP	178.221	112.670	20,080	0.1304%	2.38%	11.65%	0.0031%	0.0152%
Xcel Energy Inc	XEL	507.211	33.730	17,108	0.1111%	3.79%	5.05%	0.0042%	0.0056%
Rockwell Collins Inc	COL	131.770	81.850	10,785	0.0700%	1.61%	9.88%	0.0011%	0.0069%
FMC Technologies Inc	FTI	229.474	34.780	7,981	0.0000%	n/a	7.58%	n/a	0.0000%
Zimmer Biomet Holdings Inc	ZBH	203.365	103.560	21,060	0.1367%	0.85%	10.87%	0.0012%	0.0149%
CBRE Group Inc	CBG	333.180	32.020	10,668	0.0000%	n/a	10.50%	n/a	0.0000%
Signet Jewelers Ltd	SIG	80.127	138.000	11,058	0.0718%	0.64%	8.00%	0.0005%	0.0057%
MasterCard Inc	MA	1,108.884	92.370	102,428	0.6650%	0.69%	16.58%	0.0046%	0.1103%
GameStop Corp	GME	106.720	42.480	4,533	0.0294%	3.39%	14.43%	0.0010%	0.0042%
CarMax Inc	KMX	208.042	61.000	12,691	0.0000%	n/a	14.98%	n/a	0.0000%
Intercontinental Exchange Inc	ICE	110.489	228.410	25,237	0.1639%	1.31%	15.55%	0.0022%	0.0255%
Fidelity National Information Services Inc	FIS	281.583	69.060	19,446	0.1263%	1.51%	12.62%	0.0019%	0.0159%
Chipotle Mexican Grill Inc	CMG	31.142	710.010	22,111	0.0000%	n/a	21.24%	n/a	0.0000%
Pepco Holdings Inc	POM	253.072	22.980	5,816	0.0378%	4.70%	4.70%	0.0018%	0.0018%
Wynn Resorts Ltd	WYNN	101.537	75.050	7,620	0.0495%	2.66%	7.90%	0.0013%	0.0039%
Hospira Inc	HSP	172.934	89.970	15,559	0.0000%	n/a	14.30%	n/a	0.0000%
Assurant Inc	AIZ	66.818	74.350	4,968	0.0323%	1.61%	8.14%	0.0005%	0.0026%
NRG Energy Inc	NRG	330.655	19.920	6,587	0.0428%	2.91%	23.90%	0.0012%	0.0102%
Genworth Financial Inc	GNW	497.419	5.180	2,577	0.0000%	n/a	5.00%	n/a	0.0000%
Monster Beverage Corp	MNST	204.193	138.460	28,273	0.0000%	n/a	20.50%	n/a	0.0000%
Regions Financial Corp	RF	1,324.907	9.590	12,706	0.0825%	2.50%	2.86%	0.0021%	0.0024%
Teradata Corp	TDC	141.600	29.230	4,139	0.0000%	n/a	8.11%	n/a	0.0000%
Mosaic Co/The	MOS	337.159	40.830	13,766	0.0894%	2.69%	9.30%	0.0024%	0.0083%
Expedia Inc	EXPE	116.334	114.990	13,377	0.0869%	0.83%	13.75%	0.0007%	0.0119%
Discovery Communications Inc	DISCA	149.302	26.600	3,971	0.0000%	n/a	13.57%	n/a	0.0000%
CF Industries Holdings Inc	CF	233.048	57.380	13,372	0.0868%	2.09%	12.00%	0.0018%	0.0104%
Viacom Inc	VIAB	347.460	40.770	14,166	0.0920%	3.92%	9.25%	0.0036%	0.0085%
Google Inc	GOOG	343.929	618.250	212,634	0.0000%	n/a	17.33%	n/a	0.0000%
Wyndham Worldwide Corp	WYN	118.111	76.480	9,033	0.0586%	2.20%	10.00%	0.0013%	0.0059%
Spectra Energy Corp	SE	671.363	29.070	19,517	0.1267%	5.09%	3.85%	0.0065%	0.0049%
First Solar Inc	FSLR	100.903	47.840	4,827	0.0000%	n/a	-2.95%	n/a	0.0000%
Ensco PLC	ESV	235.679	18.110	4,268	0.0000%	3.31%	n/a	0.0000%	n/a
Mead Johnson Nutrition Co	MJN	202.739	78.340	15,883	0.1031%	2.11%	8.80%	0.0022%	0.0091%
TE Connectivity Ltd	TEL	402.384	59.290	23,857	0.1549%	2.23%	10.45%	0.0034%	0.0162%

U.S. Forward-Looking MRP Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Discover Financial Services	DFS	435.307	53.730	23,389	0.1519%	2.08%	9.22%	0.0032%	0.0140%
TripAdvisor Inc	TRIP	131.296	69.900	9,178	0.0000%	n/a	20.05%	n/a	0.0000%
Dr Pepper Snapple Group Inc	DPS	190.886	76.730	14,647	0.0951%	2.50%	7.26%	0.0024%	0.0069%
Scripps Networks Interactive Inc	SNI	94.201	53.090	5,001	0.0325%	1.73%	11.45%	0.0006%	0.0037%
Visa Inc	V	1,951.387	71.300	139,134	0.9034%	0.67%	18.08%	0.0061%	0.1634%
Xylem Inc/NY	XYL	181.499	32.450	5,890	0.0382%	1.74%	9.87%	0.0007%	0.0038%
Marathon Petroleum Corp	MPC	536.157	47.310	25,366	0.1647%	2.71%	2.58%	0.0045%	0.0043%
Tractor Supply Co	TSCO	135.819	85.310	11,587	0.0752%	0.94%	15.33%	0.0007%	0.0115%
Level 3 Communications Inc	LVLT	355.833	44.730	15,916	0.0000%	n/a	26.99%	n/a	0.0000%
Transocean Ltd	RIG	363.554	14.230	5,173	0.0336%	4.22%	-25.40%	0.0014%	-0.0085%
Essex Property Trust Inc	ESS	65.744	214.620	14,110	0.0916%	2.68%	8.18%	0.0025%	0.0075%
General Growth Properties Inc	GGP	885.657	25.380	22,478	0.1459%	2.68%	7.91%	0.0039%	0.0115%
Realty Income Corp	O	234.869	44.690	10,496	0.0681%	5.10%	3.92%	0.0035%	0.0027%
Seagate Technology PLC	STX	302.034	51.400	15,525	0.1008%	4.20%	8.30%	0.0042%	0.0084%
WestRock Co	WRK	261.848	59.350	15,541	0.1009%	2.53%	7.46%	0.0026%	0.0075%
Western Digital Corp	WDC	230.403	81.960	18,884	0.1226%	2.44%	5.00%	0.0030%	0.0061%
Fossil Group Inc	FOSL	48.147	61.580	2,965	0.0000%	n/a	11.13%	n/a	0.0000%
JB Hunt Transport Services Inc	JBHT	116.251	72.780	8,461	0.0549%	1.15%	14.83%	0.0006%	0.0081%
Lam Research Corp	LRCX	158.187	72.770	11,511	0.0747%	1.65%	6.41%	0.0012%	0.0048%
Mohawk Industries Inc	MHK	73.913	196.970	14,559	0.0000%	n/a	12.05%	n/a	0.0000%
Pentair PLC	PNR	180.056	55.290	9,955	0.0646%	2.32%	14.40%	0.0015%	0.0093%
Vertex Pharmaceuticals Inc	VRTX	244.656	127.520	31,199	0.0000%	n/a	25.67%	n/a	0.0000%
Facebook Inc	FB	2,259.737	89.430	202,088	0.0000%	n/a	24.17%	n/a	0.0000%
United Rentals Inc	URI	95.370	69.330	6,612	0.0000%	n/a	12.20%	n/a	0.0000%
Navient Corp	NAVI	374.033	12.790	4,784	0.0000%	5.00%	n/a	0.0000%	n/a
Delta Air Lines Inc	DAL	795.398	43.780	34,823	0.2261%	1.23%	22.14%	0.0028%	0.0501%
Baxalta Inc	BXLT	676.969	35.150	23,795	0.1545%	0.80%	4.55%	0.0012%	0.0070%
Mallinckrodt PLC	MNK	117.343	86.240	10,120	0.0000%	n/a	13.05%	n/a	0.0000%
Keurig Green Mountain Inc	GMCR	154.058	56.600	8,720	0.0566%	2.03%	14.20%	0.0012%	0.0080%
Macerich Co/The	MAC	158.321	76.180	12,061	0.0783%	3.41%	6.31%	0.0027%	0.0049%
Martin Marietta Materials Inc	MLM	67.001	167.800	11,243	0.0730%	0.95%	24.07%	0.0007%	0.0176%
PayPal Holdings Inc	PYPL	1,218.736	35.000	42,656	0.0000%	n/a	16.75%	n/a	0.0000%
Alexion Pharmaceuticals Inc	ALXN	226.155	172.190	38,942	0.0000%	n/a	23.19%	n/a	0.0000%
Columbia Pipeline Group Inc	CPGX	317.615	25.360	8,055	0.0523%	1.97%	36.00%	0.0010%	0.0188%
Endo International PLC	ENDP	208.251	77.000	16,035	0.0000%	n/a	8.97%	n/a	0.0000%
News Corp	NWSA	380.999	13.630	5,193	0.0337%	1.47%	10.35%	0.0005%	0.0035%
Crown Castle International Corp	CCI	333.762	83.390	27,832	0.1807%	3.93%	22.67%	0.0071%	0.0410%
Delphi Automotive PLC	DLPH	284.349	75.520	21,474	0.1394%	1.32%	13.73%	0.0018%	0.0191%
Advance Auto Parts Inc	AAP	73.217	175.250	12,831	0.0833%	0.14%	13.68%	0.0001%	0.0114%
Michael Kors Holdings Ltd	KORS	193.422	43.460	8,406	0.0000%	n/a	27.34%	n/a	0.0000%
Alliance Data Systems Corp	ADS	61.433	257.190	15,800	0.0000%	n/a	14.60%	n/a	0.0000%
Nielsen Holdings PLC	NLSN	366.860	45.230	16,593	0.1077%	2.48%	14.00%	0.0027%	0.0151%
Garmin Ltd	GRMN	190.936	37.610	7,181	0.0466%	5.42%	7.95%	0.0025%	0.0037%
Cimarex Energy Co	XEC	94.456	110.510	10,438	0.0678%	0.58%	-4.37%	0.0004%	-0.0030%
Zoetis Inc	ZTS	498.944	44.870	22,388	0.1454%	0.74%	12.50%	0.0011%	0.0182%
Equinix Inc	EQIX	56.958	269.770	15,366	0.0998%	2.51%	38.74%	0.0025%	0.0386%
Discovery Communications Inc	DISCK	274.284	25.360	6,956	0.0000%	n/a	13.57%	n/a	0.0000%
Average for Companies Paying Dividends with Long-Term Growth Estimates						**2.39%**	**10.00%**	**2.58%**	**9.66%**

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P., as of August 31, 2015
[6] Source: Bloomberg Finance L.P., as of August 31, 2015
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and Best Long-Term Growth Estimate does not equal "n/a" and is greater than 0%
[9] Source: Bloomberg Finance L.P., as of August 31, 2015
[10] Source: Bloomberg Finance L.P., as of August 31, 2015
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield plus Average Daily Spread between 10-year and 30-year government bonds August 2015
[14] Equals Column [4] - (Column [13]/100)

Capital Asset Pricing Model
Betas Adjusted to Market Average of 1

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
US Proxy Group	**Ticker**	**Bloomberg**	**Value Line**	**Average Beta**	**Risk Free Rate**	**Average Market Risk Premium**	**Straight CAPM Calculation**	**Flotation Cost**	**Total CAPM**
Atmos Energy Corporation	ATO	0.72	0.85	0.78	3.68%	7.60%	9.63%	0.50%	10.13%
New Jersey Resources Corp.	NJR	0.75	0.80	0.78	3.68%	7.60%	9.58%	0.50%	10.08%
Northwest Natural Gas Company	NWN	0.68	0.70	0.69	3.68%	7.60%	8.93%	0.50%	9.43%
Piedmont Natural Gas Company, Inc.	PNY	0.79	0.80	0.79	3.68%	7.60%	9.70%	0.50%	10.20%
South Jersey Industries, Inc.	SJI	0.78	0.85	0.81	3.68%	7.60%	9.86%	0.50%	10.36%
Southwest Gas Corporation	SWX	0.77	0.85	0.81	3.68%	7.60%	9.83%	0.50%	10.33%
WGL Holdings, Inc.	WGL	0.73	0.80	0.76	3.68%	7.60%	9.49%	0.50%	9.99%
MEAN		0.74	0.81	0.78	3.68%		9.58%		10.08%
Canadian Proxy Group									
Canadian Utilities Limited	CU	0.62		0.62	3.68%	7.60%	8.36%	0.50%	8.86%
Emera Inc.	EMA	0.71		0.71	3.68%	7.60%	9.07%	0.50%	9.57%
Enbridge Inc.	ENB	0.79		0.79	3.68%	7.60%	9.70%	0.50%	10.20%
Fortis Inc.	FTS	0.68		0.68	3.68%	7.60%	8.81%	0.50%	9.31%
Valener Inc.	VNR	0.43		0.43	3.68%	7.60%	6.97%	0.50%	7.47%
MEAN		0.65		0.65	3.68%		8.58%		9.08%

Notes:
[1] Source: Bloomberg Professional; beta computed on five years of weekly returns, as of August 31, 2015, against the S&P 500 and the S&P/TSX for the U.S. and Canadian proxy groups, respectively.
[2] Source: Value Line; beta computed on five years of weekly market-adjusted returns against the NYSE.
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term forecast of 10-year Canadian government bond yield for the period 2016-2018, published by Consensus Forecasts April 13, 2015 plus the 30-day average spread between 10- and 30-year Canadian bond ending June 30, 2015, per Bloomberg data
[5] Source: Average of the Duff & Phelps Canada historical risk premium (1919-2014) of 5.6%, Duff & Phelps US historical risk premium (1926-2012) of 7%, both in local currency. Duff and Phelps, 2015 International Valuation Handbook through December 2014 and March 2015; Data Exhibit 1-9 and 1-40.and the Canadian forward looking risk premium (JMC-4 Schedule 1) of 9.78%, and the U.S. forward looking risk premium of (JMC-4 Schedule 2) of 8.08%.
[6] Equals [4] + [3] x [5]
[7] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[8] Equals [6] + [7]

Capital Asset Pricing Model
Average of Betas Adjusted to Market Average of 1 and Industry Average

US Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta Adjusted to Market	[4] Raw Beta	[5] Industry Index Beta	[6] Beta Adjusted to Industry Average	[7] Average Beta	[8] Risk Free Rate	[9] Average Market Risk Premium	[10] CAPM Calculation	[11] Flotation Cost	[12] Total CAPM
Atmos Energy Corporation	ATO	0.72	0.85	**0.78**	0.57	0.47	**0.54**	**0.66**	3.68%	7.60%	8.71%	0.50%	9.21%
New Jersey Resources Corp.	NJR	0.75	0.80	**0.78**	0.63	0.47	**0.58**	**0.68**	3.68%	7.60%	8.83%	0.50%	9.33%
Northwest Natural Gas Company	NWN	0.68	0.70	**0.69**	0.52	0.47	**0.51**	**0.60**	3.68%	7.60%	8.22%	0.50%	8.72%
Piedmont Natural Gas Company, Inc.	PNY	0.79	0.80	**0.79**	0.68	0.47	**0.61**	**0.70**	3.68%	7.60%	9.00%	0.50%	9.50%
South Jersey Industries, Inc.	SJI	0.78	0.85	**0.81**	0.66	0.47	**0.60**	**0.71**	3.68%	7.60%	9.04%	0.50%	9.54%
Southwest Gas Corporation	SWX	0.77	0.85	**0.81**	0.65	0.47	**0.59**	**0.70**	3.68%	7.60%	9.01%	0.50%	9.51%
WGL Holdings, Inc.	WGL	0.73	0.80	**0.76**	0.59	0.47	**0.55**	**0.66**	3.68%	7.60%	8.68%	0.50%	9.18%
MEAN		0.74	0.81	**0.78**	0.62	0.47	**0.57**	**0.67**	3.68%		8.78%		9.28%
Canadian Proxy Group													
Canadian Utilities Limited	CU	0.62		**0.62**	0.42	0.54	**0.46**	**0.54**	3.68%	7.60%	7.78%	0.50%	8.28%
Emera Inc.	EMA	0.71		**0.71**	0.56	0.54	**0.56**	**0.63**	3.68%	7.60%	8.49%	0.50%	8.99%
Enbridge Inc.	ENB	0.79		**0.79**	0.69	0.54	**0.64**	**0.72**	3.68%	7.60%	9.12%	0.50%	9.62%
Fortis Inc.	FTS	0.68		**0.68**	0.51	0.54	**0.52**	**0.60**	3.68%	7.60%	8.23%	0.50%	8.73%
Valener Inc.	VNR	0.43		**0.43**	0.15	0.54	**0.28**	**0.36**	3.68%	7.60%	6.39%	0.50%	6.89%
MEAN		0.65		**0.65**	0.47	0.54	**0.49**	**0.57**	3.68%		8.00%		8.50%

Notes:
[1] Source: Bloomberg Professional; beta computed on five years of weekly returns, as of August 31, 2015, against the S&P 500 and the S&P/TSX for the U.S. and Canadian proxy groups, respectively.
[2] Source: Value Line; beta computed on five years of weekly market-adjusted returns against the NYSE.
[3] Equals mean of [1] and [2]
[4] Source: Bloomberg Professional; beta computed on five years of weekly returns as of August 31, 2015
[5] Source: Bloomberg Professional; beta computed on five years of weekly returns for U.S. S&P utilities index and S&P/TSX Utilities index for Canada, through August 31, 2015.
[6] Equals (2/3) x [4] + (1/3) x [5]
[7] Equals mean of [3] and [6]
[8] Equals average long-term forecast of 10-year Canadian government bond yield for the period 2016-2018, published by Consensus Forecasts April 13, 2015 plus the 30-day average spread between 10- and 30-year Canadian bond ending June 30, 2015, per Bloomberg data
[9] Equals average of the Duff & Phelps Canada historical risk premium (1919-2014) of 5.6%, Duff & Phelps US historical risk premium (1926-2012) of 7%, both in local currency. Duff and Phelps, 2015 International Valuation Handbook: Guide to Cost of Capital, Market Results through December 2014 and March 2015; Data Exhibit 1-9 and 1-40.
Canadian forward looking risk premium (JMC-4 Schedule 1) of 9.78%, and U.S. forward looking risk premium (JMC-4 Schedule 1) of 8.08%.
[10] Equals [8] + [7] x 9]
[11] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[12] Equals [10] + [11]

Regression Analysis of MRP to GOC Long-term Bond Yields from 1976 - 2014

	[1]	[2]	[3]
Year	Canada Long Bond	Dummy	MRP
1976	9.61	0	-0.2
1977	9.15	0	-2.3
1978	9.57	0	21.7
1979	10.50	0	40.8
1980	12.82	0	12.4
1981	15.59	0	-23.8
1982	14.75	0	-8.7
1983	12.08	0	22.1
1984	13.00	0	-13.6
1985	11.20	0	11.5
1986	9.30	0	-0.4
1987	9.75	0	-1.3
1988	10.05	0	-2.1
1989	9.66	0	11.4
1990	10.69	0	-22.1
1991	9.72	0	1.3
1992	8.68	0	-11.6
1993	7.86	0	15.2
1994	8.69	0	-4.3
1995	8.41	0	6.9
1996	7.75	0	22.4
1997	6.66	0	11.7
1998	5.59	0	-4.4
1999	5.72	0	40.5
2000	5.71	0	3.3
2001	5.76	0	-20.8
2002	5.68	0	-19.4
2003	5.34	0	21.4
2004	5.14	0	8.7
2005	4.40	0	21
2006	4.28	0	13.7
2007	4.32	0	6.2
2008	4.05	1	-35.5
2009	3.90	0	29.9
2010	3.73	0	11.1
2011	3.29	0	-12.1
2012	2.43	0	3.7
2013	2.84	0	11.1
2014	2.73	0	8.7

Notes and Results of Analysis:

[1] Bank of Canada, Data and Statistics Office, Selected Government of Canada Benchmark Bond Yields - Long Term

[2] Dummy Variable for Global Economic Crisis in 2008

[3] MRP from Morningstar Ibbotson through 2011, and Duff & Phelps from 2011-2014

			Forecast 30-Yr. Bond Yield	August 31, 2015 30-Yr. Bond Yield
[4]	Intercept		14.18%	14.18%
[5]	Coefficient for Canadian Long Bond		-1.11%	-1.11%
[6]	Coefficient for Global Economic Crisis		-45.18%	-45.18%
[7]	Lower Bound of Confidence Interval for Canadian Long Bond Yield Coefficient		-2.62%	-2.62%
[8]	Upper Bound of Confidence Interval for Canadian Long Bond Yield Coefficient		0.40%	0.40%
[9]	Forecast 30-Yr. Gov. Bond Yield (See Exhibit JMC-5, Note [4]), and August 31, 2015 30-Yr. Gov. bond yield		3.68	2.23
[10]	Canadian Proxy Group Beta		0.65	0.65
[11]	**Calculation of Market Risk Premium**	**= [4] +([9] x [5])+ (0 x [6])**	**10.09%**	**11.70%**
[12]	**Calculation of Canadian Utility ROE = [9] + ([10]*[11])**		**10.19%**	**9.78%**

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.445710901
R Square	0.198658207
Adjusted R Square	0.154139219
Standard Error	15.63258952
Observations	39

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2180.986958	1090.493479	4.462325	0.018566
Residual	36	8797.602785	244.3778551		
Total	38	10978.58974			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	14.17709047	6.345553584	2.234177095	0.031773	1.307711	27.04647	1.307711	27.04647
Canada Long Bond	-1.11059494	0.745857732	-1.48901713	0.145192	-2.62326	0.402075	-2.62326	0.402075
Dummy	-45.18473394	16.0825281	-2.809554174	0.00797	-77.8016	-12.5679	-77.8016	-12.5679

RESIDUAL OUTPUT

Observation	*Predicted MRP*	*Residuals*	*Standard Residuals*
1	3.503347603	-3.703347603	-0.243390768
2	4.012370284	-6.312370284	-0.414860504
3	3.545920409	18.15407959	1.193119266
4	2.511216123	38.28878388	2.516408805
5	-0.064438643	12.46443864	0.819185672
6	-3.137084645	-20.66291536	-1.358004535
7	-2.206035886	-6.493964114	-0.426795182
8	0.762954587	21.33704541	1.402309593
9	-0.262494741	-13.33750526	-0.876565205
10	1.738427143	9.761572857	0.641548396
11	3.843930051	-4.243930051	-0.278918834
12	3.346938815	-4.646938815	-0.305405306
13	3.019313308	-5.119313308	-0.33645062
14	3.445966864	7.954033136	0.522753584
15	2.302054075	-24.40205408	-1.60374756
16	3.38766063	-2.08766063	-0.137204869
17	4.535275401	-16.1352754	-1.060439768
18	5.450590731	9.749409269	0.640748983
19	4.529722427	-8.829722427	-0.580305484
20	4.84068901	2.05931099	0.135341679
21	5.571830679	16.82816932	1.105978022
22	6.779602676	4.920397324	0.323377498
23	7.967939263	-12.36793926	-0.812843556
24	7.822636425	32.67736358	2.147616014
25	7.836518861	-4.536518861	-0.298148305
26	7.780063619	-28.58006362	-1.878333978
27	7.868911214	-27.26891121	-1.792162647
28	8.251140972	13.14885903	0.86416703
29	8.474185456	0.225814544	0.014840944
30	9.288621746	11.71137825	0.769693168
31	9.420042147	4.279957853	0.281286647
32	9.374692854	-3.174692854	-0.208646612
33	-35.5	-1.42109E-14	-9.33963E-16
34	9.851323182	20.04867682	1.317635656
35	10.03919883	1.060801174	0.069717791
36	10.52323312	-22.62323312	-1.486840199
37	11.47649378	-7.776493778	-0.511085374
38	11.02300084	0.076999156	0.005060525
39	11.14424079	-2.444240792	-0.160639969

PROBABILITY OUTPUT

Percentile	*MRP*
1.282051	-35.5
3.846154	-23.8
6.410256	-22.1
8.974359	-20.8
11.53846	-19.4
14.10256	-13.6
16.66667	-12.1
19.23077	-11.6
21.79487	-8.7
24.35897	-4.4
26.92308	-4.3
29.48718	-2.3
32.05128	-2.1
34.61538	-1.3
37.17949	-0.4
39.74359	-0.2
42.30769	1.3
44.87179	3.3
47.4359	3.7
50	6.2
52.5641	6.9
55.12821	8.7
57.69231	8.7
60.25641	11.1
62.82051	11.1
65.38462	11.4
67.94872	11.5
70.51282	11.7
73.07692	12.4
75.64103	13.7
78.20513	15.2
80.76923	21
83.33333	21.4
85.89744	21.7
88.46154	22.1
91.02564	22.4
93.58974	29.9
96.15385	40.5
98.71795	40.8

90-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Flotation Cost	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Corporation	ATO	$1.56	$53.89	2.89%	3.00%	7.00%	6.80%	7.00%	7.00%	6.95%	0.50%	10.29%	10.45%	10.50%
New Jersey Resources Corporation	NJR	$0.90	$29.05	3.10%	3.18%	6.00%	6.00%	2.50%	6.00%	5.13%	0.50%	6.14%	8.80%	9.69%
Northwest Natural Gas Company	NWN	$1.86	$44.18	4.21%	4.31%	4.00%	4.00%	7.00%	4.00%	4.75%	0.50%	8.79%	9.56%	11.86%
Piedmont Natural Gas Company, Inc.	PNY	$1.32	$37.23	3.55%	3.63%	5.00%	6.00%	3.00%	5.00%	4.75%	0.50%	7.10%	8.88%	10.15%
South Jersey Industries, Inc.	SJI	$1.01	$25.37	3.96%	4.10%	n/a	n/a	8.50%	6.00%	7.25%	0.50%	10.58%	11.85%	13.13%
Southwest Gas Corporation	SWX	$1.62	$54.61	2.97%	3.04%	5.00%	4.00%	6.00%	4.00%	4.75%	0.50%	7.53%	8.29%	9.56%
WGL Holdings, Inc.	WGL	$1.85	$55.64	3.33%	3.42%	6.00%	6.90%	4.50%	6.50%	5.98%	0.50%	8.40%	9.90%	10.84%
MEAN		$1.45	$42.85	3.43%	3.53%	5.50%	5.62%	5.50%	5.50%	5.65%	0.50%	8.40%	9.68%	10.82%

Notes:
[1] Source: Bloomberg Professional as of August 31, 2015
[2] Source: Bloomberg Professional, equals 90-day average as of August 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks at August 31, 2015. n/a indicates growth rate not available on Zacks.com.
[6] Source: SNL Financial accessed September 1, 2015; Median Long Term Growth Rate. n/a indicates growth rate not available on SNL.
[7] Source: Value Line, June 5, 2015. n/a indicates growth rate not available through Value Line.
[8] Source: Yahoo! Finance at August 31, 2015. n/a indicates growth rate not available on Yahoo! Finance.
[9] Equals Average([5], [6], [7], [8])
[10] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[11] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8]) + [10]
[12] Equals [4] + [9] + [10]
[13] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8]) + [10]

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Flotation Cost	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	$1.18	$36.40	3.24%	3.31%	n/a	3.60%	n/a	4.78%	4.19%	0.50%	7.40%	8.00%	8.60%
Emera Inc.	EMA	$1.60	$41.80	3.83%	3.93%	n/a	4.50%	n/a	5.99%	5.25%	0.50%	8.91%	9.67%	10.43%
Enbridge Inc.	ENB	$1.86	$58.28	3.19%	3.41%	12.00%	n/a	10.50%	18.40%	13.63%	0.50%	14.36%	17.54%	22.39%
Fortis Inc.	FTS	$1.36	$37.30	3.65%	3.81%	n/a	8.70%	7.00%	11.50%	9.07%	0.50%	11.27%	13.38%	15.86%
Valener Inc.	VNR	$1.04	$16.84	6.18%	6.42%	n/a	n/a	n/a	8.00%	8.00%	0.50%	14.92%	14.92%	14.92%
MEAN		$1.41	$38.12	4.02%	4.18%	12.00%	5.60%	8.75%	9.73%	8.03%	0.50%	11.37%	12.70%	14.44%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks at August 31, 2015. n/a indicates growth rate not available on Zacks.com.
[6] Source: SNL Financial accessed September 1, 2015; Median Long Term Growth Rate. n/a indicates growth rate not available on SNL.
[7] Source: Value Line, June 5, 2015 (ENB) and July 17, 2015 (FTS). n/a indicates growth rate not available through Value Line.
[8] Source: Yahoo! Finance at August 31. n/a indicates growth rate not available on Yahoo! Finance.
[9] Equals Average([5], [6], [7], [8])
[10] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[11] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8]) + [10]
[12] Equals [4] + [9] + [10]
[13] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8]) + [10]

90-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE	Flotation Cost	Total ROE
Atmos Energy Corporation	ATO	$1.56	$53.89	6.95%	6.55%	6.15%	5.75%	5.35%	4.95%	4.55%	8.07%	0.50%	8.57%
New Jersey Resources Corporation	NJR	$0.90	$29.05	5.13%	5.03%	4.93%	4.84%	4.74%	4.65%	4.55%	7.91%	0.50%	8.41%
Northwest Natural Gas Company	NWN	$1.86	$44.18	4.75%	4.72%	4.68%	4.65%	4.62%	4.58%	4.55%	9.01%	0.50%	9.51%
Piedmont Natural Gas Company, Inc.	PNY	$1.32	$37.23	4.75%	4.72%	4.68%	4.65%	4.62%	4.58%	4.55%	8.30%	0.50%	8.80%
South Jersey Industries, Inc.	SJI	$1.01	$25.37	7.25%	6.80%	6.35%	5.90%	5.45%	5.00%	4.55%	9.44%	0.50%	9.94%
Southwest Gas Corporation	SWX	$1.62	$54.61	4.75%	4.72%	4.68%	4.65%	4.62%	4.58%	4.55%	7.68%	0.50%	8.18%
WGL Holdings, Inc.	WGL	$1.85	$55.64	5.98%	5.74%	5.50%	5.26%	5.03%	4.79%	4.55%	8.35%	0.50%	8.85%
MEAN		$1.45	$42.85	5.65%	5.47%	5.28%	5.10%	4.92%	4.73%	4.55%	8.39%	0.50%	8.89%

Notes:

[1] Source: Bloomberg Professional as of August 31, 2015
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Source: Exhibit JMC-5, Schedule 1
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 13, 2015. Long Term Forecasts 2021-2025: Real GDP Estimate x (1 + Inflation Estimate) + Inflation Estimate
[10] Internal rate of return
[11] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[12] Equals [10] + [11]

90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE	Flotation Cost	Total ROE
Canadian Utilities Limited	CU	$1.18	$36.40	4.19%	4.15%	4.11%	4.06%	4.02%	3.98%	3.94%	7.36%	0.50%	7.86%
Emera Inc.	EMA	$1.60	$41.80	5.25%	5.03%	4.81%	4.59%	4.37%	4.16%	3.94%	8.26%	0.50%	8.76%
Enbridge Inc.	ENB	$1.86	$58.28	13.63%	12.02%	10.40%	8.79%	7.17%	5.55%	3.94%	9.84%	0.50%	10.34%
Fortis Inc.	FTS	$1.36	$37.30	9.07%	8.21%	7.36%	6.50%	5.65%	4.79%	3.94%	9.12%	0.50%	9.62%
Valener Inc.	VNR	$1.04	$16.84	8.00%	7.32%	6.65%	5.97%	5.29%	4.62%	3.94%	12.02%	0.50%	12.52%
MEAN		$1.41	$38.12	8.03%	7.35%	6.66%	5.98%	5.30%	4.62%	3.94%	9.32%	0.50%	9.82%

Notes:
[1] Source: Bloomberg Professional as of August 31, 2015
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Source: Exhibit JMC-5, Schedule 1
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 13, 2015. Long Term Forecasts 2021-2025: Real GDP Estimate x (1 + Inflation Estimate) + Inflation Estimate
[10] Internal rate of return
[11] Flotation Costs Allowed by the BCUC in GCOC Decision (Stage 1), May 10, 2013 at 80.
[12] Equals [10] + [11]

U.S. Proxy Group Capital Structure
Most Recent Quarter

Company	Ticker	Short Term Debt (Thousands)	Long Term Debt (Thousands)	Debt (Thousands)	%	Preferred Stock (Thousands)	%	Equity (Thousands)	%	Total Capital (Thousands)
Atmos Energy Corporation	ATO	251,977	2,455,303	2,707,280	46%	0	0%	3,238,255	54%	5,945,535
New Jersey Resources, Inc	NJR	36,032	847,521	883,553	44%	0	0%	1,123,312	56%	2,006,865
Northwest Natural Gas Company	NWN	190,300	621,700	812,000	51%	0	0%	776,964	49%	1,588,964
Piedmont Natural Gas Company, Inc.	PNY	255,000	1,424,443	1,679,443	54%	0	0%	1,432,560	46%	3,112,003
South Jersey Industries, Inc.	SJI	451,909	859,491	1,311,400	57%	0	0%	969,977	43%	2,281,377
Southwest Gas Corporation	SWX	20,050	1,521,683	1,541,733	50%	0	0%	1,549,633	50%	3,091,366
WGL Holdings Inc.	WGL	201,000	950,494	1,151,494	47%	0	0%	1,294,546	53%	2,446,040
Proxy Group Average		200,895	1,240,091	1,440,986	50%	0	0%	1,483,607	50%	2,924,593

Canadian Proxy Group Capital Structure
Most Recent Quarter

Company	Ticker	Short Term Debt (Thousands Canadian $)	Long Term Debt (Thousands Canadian $)	Debt (Thousands Canadian $)	%	Preferred Stock (Thousands Canadian $)	%	Equity (Thousands Canadian $)	%	Total Capital (Thousands Canadian $)
Canadian Utilities Limited	CU	469,000	7,299,000	7,768,000	58%	1,115,000	8%	4,590,000	34%	13,473,000
Emera Inc.	EMA	99,100	3,613,500	3,712,600	48%	709,500	9%	3,290,500	43%	7,712,600
Enbridge Inc.	ENB	2,061,000	36,309,000	38,370,000	64%	8,430,000	14%	13,103,000	22%	59,903,000
Fortis Inc.	FTS	1,055,000	11,129,000	12,184,000	56%	1,820,000	8%	7,927,000	36%	21,931,000
Valener Inc.	VNR	-	99,496	99,496	12%	97,480	11%	661,784	77%	858,760
Proxy Group Average		736,820	11,689,999	12,426,819	47%	2434396	10%	5,914,457	42%	20,775,672

Notes:
Data downloaded from SNL Financial. Most recent quarter ends June 30, 2015 for all companies, except Piedmont Natural Gas Company, Inc. which ends April 30, 2015.

U.S. Proxy Group Capital Structure
Fiscal Year Ended 2014

Company	Ticker	Short Term Debt	Long Term Debt	Debt (Thousands)	%	Preferred Stock (Thousands)	%	Equity (Thousands)	%	Total Capital (Thousands)
Atmos Energy Corporation	ATO	196,881	2,456,313	2,653,194	46%	0	0%	3,086,232	54%	5,739,426
New Jersey Resources, Inc	NJR	335,505	598,209	933,714	49%	0	0%	966,166	51%	1,899,880
Northwest Natural Gas Company	NWN	275,380	622,424	897,804	54%	0	0%	767,321	46%	1,665,125
Piedmont Natural Gas Company, Inc.	PNY	355,000	1,424,430	1,779,430	58%	0	0%	1,308,602	42%	3,088,032
South Jersey Industries, Inc.	SJI	395,609	859,491	1,255,100	57%	0	0%	932,432	43%	2,187,532
Southwest Gas Corporation	SWX	19,192	1,637,592	1,656,784	53%	0	0%	1,486,266	47%	3,143,050
WGL Holdings Inc.	WGL	473,500	679,228	1,152,728	47%	0	0%	1,274,749	53%	2,427,477
Proxy Group Average		293,010	1,182,527	1,475,536	52%	0	0%	1,403,110	48%	2,878,646

Canadian Proxy Group Capital Structure
Fiscal Year Ended 2014

Company	Ticker	Short Term Debt (Thousands Canadian $)	Long Term Debt (Thousands Canadian $)	Debt (Thousands Canadian $)	%	Preferred Stock (Thousands Canadian $)	%	Equity (Thousands Canadian $)	%	Total Capital (Thousands Canadian $)
Canadian Utilities Limited	CU	102,000	7,217,000	7,319,000	57%	1,115,000	9%	4,492,000	35%	12,926,000
Emera Inc.	EMA	352,100	3,660,300	4,012,400	52%	709,500	9%	2,995,900	39%	7,717,800
Enbridge Inc.	ENB	2,552,000	33,423,000	35,975,000	63%	8,764,000	15%	12,286,000	22%	57,025,000
Fortis Inc.	FTS	1,063,000	10,471,000	11,534,000	56%	1,820,000	9%	7,292,000	35%	20,646,000
Valener Inc.	VNR	-	66,780	66,780	9%	97,480	12%	615,983	79%	780,243
Proxy Group Average		813,820	10,967,616	11,781,436	47%	2501196	11%	5,536,377	42%	19,819,009

Adjusting U.S. Proxy Group Results to FEI Leverage

Leverage Adjustment Using WACC Formula:

$$ROE_{UL} = \frac{ROE_L + (d*(D/E)*(1-T_C)}{1+(D/E)*(1-T_C)}$$

$$ROE_{RL} = ROE_{UL} + (ROE_{UL} - d) * (D/E)* (1-T_C)$$

ROE_{UL} = unlevered ROE (at book cap structure)
ROE_{RL} = relevered ROE (at book cap structure)
ROE_L = levered original ROE (proxy group)
D = Debt Ratio
E = Equity Ratio
d = debt cost
T_C = Corporate tax rate

	Lower Bound	Upper Bound	
ROE_{L}=	8.89%	10.08%	[1]
d=	4.02%	4.02%	[2]
D_0=	52.07%	52.07%	[3]
E_0=	47.93%	47.93%	[3]
T_c=	34.46%	34.46%	[4]
D_1=	61.50%	61.50%	[5]
E_1=	38.50%	38.50%	[5]
ROE_{UL}=	6.86%	7.56%	[6]
ROE_{RL}=	9.84%	11.27%	[7]
Diff	0.95%	1.19%	[8]

Company	Ticker	2014 Interest Paid and Accrued	2014 Total Debt	[2] 2014 Debt Cost	2014 Provision for Taxes	2014 Net Income before Taxes	2014 Debt Cost
Atmos Energy Corporation	ATO	$ 130,817	$ 2,653,194	4.93%	$ 187,002	$ 476,819	39.22%
New Jersey Resources, Inc	NJR	26,520	933,714	2.84%	51,840	193,810	26.75%
Northwest Natural Gas Company	NWN	42,600	897,804	4.74%	41,643	100,335	41.50%
Piedmont Natural Gas Company, Inc.	PNY	69,942	1,779,430	3.93%	94,818	238,619	39.74%
South Jersey Industries, Inc.	SJI	34,196	1,255,100	2.72%	4,449	102,077	4.36%
Southwest Gas Corporation	SWX	73,297	1,661,784	4.41%	78,373	219,521	35.70%
WGL Holdings Inc.	WGL	37,738	1,152,728	3.27%	57,254	164,514	34.80%
Proxy Group Average		$ 59,301	$ 1,476,251	4.02%	$ 73,626	$ 213,671	34.46%

Notes:

[1] Low and high ROE results for the U.S. proxy group based on analyses at JMC-5 and JMC-7
[2] Debt cost obtained by dividing "interest paid and accrued" by "total debt costs" for 2014 accessed through SNL Financial
[3] Per Exhibit JMC-8 for the year ended 2014
[4] Corporate tax rate was calculated by dividing "provision for income taxes" by "net income before taxes" for year end 2014 accessed through SNL Financial
[5] Per Exhibit JMC-8 for the year ended 2015
[6] Calculated as indicated above
[7] Calculated as indicated above
[8] Leverage adjustment to U.S. proxy group results is calculated by subtracting [1] from [7]

Appendix C

FEI BUSINESS RISK ASSESSMENT

Appendix C

FortisBC Energy Inc.

Business Risk Assessment

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1. INTRODUCTION

The assessment of a utility's risk profile is an essential element of its cost of capital estimation process. The FortisBC Utilities (FBCU or the Companies) provided a detailed description of FEI's business risk profile as Appendix H of their evidence in the Generic Cost of Capital Proceeding – Stage 1 (GCOC Stage 1). Further, a comparison of FEI's business risk profile with that of FEVI and FEW was provided as Appendix A of its evidence in the Generic Cost of Capital Proceeding – Stage 2 (GCOC Stage 2). In those appendices, the Companies described their overall competitive, operating, policy and regulatory environment using specific categories of business risk and risk factors.

Since the filing of evidence in GCOC Stage 1 and GCOC Stage 2, on February 26, 2014 by Order G-21-14, the Commission approved the amalgamation of FEI, FEVI and FEW. On May 23, 2014, the Lieutenant Governor in Council issued Order in Council No. 300 consenting to the amalgamation. The amalgamated entity is carrying on business as FEI, and in this Appendix will be referred to as "FEI", "amalgamated FEI" or "FEI Amalco".

This Appendix describes amalgamated FEI's overall competitive, operating, policy and regulatory environment using the same categories of business risk and risk factors that had been used in the Companies' GCOC filings. FEI assesses any changes to its risk profile from two perspectives:

FEI has assessed how its risk profile has changed in comparison to risks defined in GCOC Stage 1 as a result of factors other than the amalgamation itself. The analysis addresses, for instance, changes in commodity prices and regulatory and political developments since 2012.

FEI has also considered the extent to which FEI's risk profile has changed as a result of amalgamating with FEVI and FEW. In GCOC Stage 2, the FBCU stated that FEVI's and FEW's risk profiles were higher than that of FEI due primarily to (a) greater concentration of assets within a small service area, (b) less diverse customer and economic base, (c) greater challenge in terms of price competitiveness, and (d) greater supply security risk due to regional infrastructure constraints and dependency on a single pipeline system that traverses challenging terrain. Amalgamation has addressed items (a), (b) and (c), for the most part[1]; however, item (d) represents an incremental risk for amalgamated FEI in comparison with pre-amalgamation FEI in the GCOC Stage 1. In addition, the effect of amalgamation on other elements of FEI's business risks will be considered in this section.

Amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (pre-amalgamation FEI) and trending higher.

[1] Until January 1 2018 when the phase-in period will be completed, the Vancouver Island and Whistler service areas continue to have higher delivery rates than the Mainland service area.

2. OVERVIEW OF BUSINESS RISK

2.1 *GENERIC BUSINESS RISK CATEGORIES AND FACTORS*

In Stage 1 of the GCOC proceeding, FEI identified eight business risk categories, as presented in Table C-1 below. FEVI and FEW used the same categories in Stage 2 of the GCOC proceeding. Other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category.[2] However, using the same categories as in the GCOC proceeding facilitates the comparison of the amalgamated FEI risk profile with business risk information presented during the GCOC proceeding.

Table C-1: Business Risk Categories and Risk Factors Addressed in this Appendix

Business Risk Category	Risk Factors
Business Profile	• Type and size of utility • Energy product offering • Service area and customer profile
Economic Conditions	• GDP • Housing starts • Unemployment
Energy Price	• Commodity price • Commodity price volatility • Upfront and installation costs
Market Shifts	• New technology and energy forms • Perception of energy • Housing types • Changes in use per customer • Changes in capture rates
Energy Supply	• Availability of supply • Security of supply
Operating	• Infrastructure integrity • Third party damages • Unexpected events
Political	• Energy policies and legislation • GHG emissions reductions • Carbon tax • Aboriginal rights
Regulatory	• Regulatory uncertainty and lag • Deferral accounts • Administrative penalties

[2] For example, availability of energy supply could also be included as a risk factor under Energy Price because the availability of supply of an energy form can impact its price.

2.2 *SUMMARY ASSESSMENT OF AMALGAMATED FEI'S BUSINESS RISK*

Table C-2 ranks the business risk categories as they apply to amalgamated FEI and by providing a summary assessment of whether the risk to amalgamated FEI associated with particular risk factors are higher/lower/same as they were for the benchmark utility (FEI prior to amalgamation). The ranking of the risk categories provided below is identical to what was provided in GCOC Stage 1, with regulatory risk being the highest risk, followed by the risk categories most directly influencing throughput, and then other risk categories relating to operations and supply.

Table C-2: Amalgamated FEI's Business Risk as Compared to 2012 Benchmark Utility

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Regulatory		**Same**		**1**
	Regulatory uncertainty and lag	Same	Same	
	Deferral accounting	Same	Same	
	Administrative penalties	Same	Same	
Energy Prices		**Same**		**2**
	Commodity prices	Lower	Same	
	Commodity price volatility	Higher	Same	
	Upfront and installation costs	Same	Same	
Market Shifts		**Same**		**2**
	New technology and energy forms	Same	Same	
	Perception of energy	Same	Same	
	Housing types	Same	Same	
	Changes in use per customer	Same	Same	
	Changes in the capture rates	Same	Same	
Political		**Higher**		**2**
	Energy policy and legislation	Same	Same	
	GHG emissions reductions initiatives and local governments policies	Higher	Same	
	Carbon tax	Same	Same	
	Aboriginal rights	Higher	Same	
Business Profile		**Same**		**2**
	Type and size of the utility	Same	Same	
	Energy product offering	Same	Same	
	Service area and customer profile	Same	Same	
Economic Conditions		**Same**		**2**
	Overall economic conditions	Same	Same	

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Operating		**Same**		**3**
	Infrastructure integrity	Same	Same	
	Third party damages	Same	Same	
	Unexpected events	Same	Same	
Energy Supply		**Higher**		**4**
	Availability of supply	Same	Same	
	Security of supply	Higher	Higher	

The key points from this "snapshot" regarding the relative risk of amalgamated FEI compared to 2012, which are discussed throughout this Appendix, are summarized by business risk category below.

- *Regulatory:* The Commission's jurisdiction is confined to what is conferred by the Utilities Commission Act (*Act*), but within that framework has significant discretion in the exercise of those powers. FEI is dependent on regulatory approvals of rates that determine its revenues and cost recoveries. The Commission establishes the level of return that is allowed to be included in rates, and establishes depreciation rates that determine a utility's ability to recover invested capital. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the fair return standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved. Compared to previous periods, the 2014 PBR Decision included some additional regulatory uncertainty and risk, although the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012, with the potential to be higher over the term of PBR.
- *Energy Prices:* The risk relating to energy prices overall remains similar to how it was characterized by FEI in 2012. While market prices are currently similar to where they were at this time in 2012, medium and long term commodity price forecasts are lower than what was expected in 2012 due to higher reserve expectations and lower production costs. However, market prices continue to remain very volatile, despite the abundance of gas supply driven by shale gas production growth. In its GCOC Stage 1 Decision, the Commission concluded that the forward price curve at that time indicated some level of stability over the next few years.[3] This has not been the case, as was highlighted by the price spikes and volatility that occurred during winter 2013/14 and the

[3] GCOC Stage 1 Decision, p.32.

subsequent fall in gas prices in 2015. In terms of competitiveness, the current price competitiveness of natural gas versus electricity has improved on an operating costs basis as electricity rates have increased relative to FEI natural gas rates. However, the upfront and installation costs have not changed significantly for natural gas versus electricity and this, along with other non-price factors, continues to add to the challenge of maintaining FEI system throughput levels. All things considered, FEI assesses that the overall risks associated with energy price are similar to that of its 2012 assessment levels.

- *Market Shifts:* The market shift in energy demand caused by continued support for new energy forms and technologies that produce energy closer to the point of consumption, along with the rate of change in housing mix and customer perceptions of energy, all continue to represent challenges to retaining and attracting customers even in the current energy price environment. Similar to 2012, the declining trend in FEI's throughput level, particularly for the residential sector, can be explained as twofold: (a) weak capture rates in the new construction market in the growing multi-family dwelling sector and (b) declining use per customer from existing and new customers caused by smaller average dwelling size as well as improvements in energy efficiency and conservation efforts supported by the provincial and local governments' policies.
- *Political:* Government policies and regulations have a significant impact on FEI's operations and competitiveness. The overall thrust of climate change and energy policies remains similar to that articulated in 2012. With the passage of time, these policies have been implemented to a greater extent. Similar to 2012, provincial government policies do not promote the use of natural gas in FEI's traditional markets of space heating and water heating while promoting the role of natural gas in the transportation sector and for LNG export. Further, local governments have intensified their "green initiatives" and in some instances have introduced updates to their bylaws and codes or have supported development of projects that can substantially hinder FEI's ability to attract new customers and/or retain existing ones. For instance, FEI's capture rates (in both commercial and residential sectors) are particularly threatened by the recent City of Vancouver decision to support mandatory connection to district energy systems for entire neighbourhoods as evidenced by its active endorsement of Creative Energy Vancouver Platforms Inc.'s CPCN for a Low Carbon Neighbourhod Energy System for Northeast False Creek and Chinatown. On the subject of Aboriginal rights and title issues, the recent Supreme Court of Canada Decision in *Tsilhqot'in Nation v. British Columbia* introduced new uncertainties. Overall, political risk is assessed as higher.
- *Business Profile:* Amalgamated FEI has a larger customer base and service territory than the 2012 benchmark utility. The business profile of the amalgamated entity is not materially different from FEI's pre-amalgamated business risk profile level. This viewpoint has been confirmed by credit agencies such as DBRS[4].

[4] Please refer to DBRS's January 2015 FEI's rating report in Appendix A.

- *Economic Conditions:* The current Canadian economic environment continues to be dominated by uncertainty. A combination of factors, from the recent drop in oil prices and a slow-down in economic growth in Europe and China, to a weaker Canadian dollar and a relatively strong U.S. recovery lead to FEI's assessment that the overall economic condition is not materially different from 2012 levels.
- *Operating:* Operating risk factors include infrastructure integrity, third party damages and unexpected events. All things considered, the overall operating risk is assessed to be similar to 2012.
- *Energy Supply:* Despite the abundance of supply associated with the development of tight and shale gas resources, the underlying infrastructure to move this natural gas to FEI's service territory (accessibility of supply) remains unchanged as compared to 2012. The development of several significant gas transmission infrastructure projects connecting BC deposits with Alberta and eastern markets in the coming years could alter the amount of gas available to FEI and the historical pricing relationship of BC supply in relation to Alberta production. This could have a negative impact to the price that consumers pay for natural gas in BC in coming years. The addition of FEVI and FEW to amalgamated FEI's service territory has slightly increased FEI's exposure to security of supply risk. As such, the overall risk is considered to be slightly higher than 2012 levels.

Considered together, amalgamated FEI's overall business risk is best characterized as being similar to that of the 2012 benchmark utility (non-amalgamated FEI) and trending higher.

3. BUSINESS PROFILE

As business risk is specific to a particular utility, it is important to understand the fundamental characteristics (or business profile) of the utility being assessed. Discussed below is a high level overview of amalgamated FEI's business profile.

In 2012, the benchmark utility (pre-amalgamated) FEI was a large natural gas distribution utility whose core business was serving space and water heating load in the residential and commercial sectors. FEI also served industrial load. The core market was experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which were central to FEI's overall business risk.

Following the amalgamation of FEI, FEVI and FEW on December 31, 2014, amalgamated FEI remains a large natural gas distribution utility. Its operations now extend to the Mainland, Vancouver Island and Whistler[5], serving approximately 970,000 customers throughout the province. However, given the already large size of the pre-amalgamation FEI, the change in size associated with the addition of the FEVI and FEW customers and rate base is not, in and of itself, a differentiating risk factor. FEI's core business remains serving space and water heating load in the residential and commercial sectors. As before, the core market is experiencing declining throughput levels and slow customer growth, while facing continued competitive challenges, which are central to FEI's overall business risk. Credit rating agencies like DBRS agree with FEI's assessment that the business profile of the amalgamated entity is not materially different from FEI's pre-amalgamated business risk profile level.[6]

Throughout this appendix, for comparability and presentation purposes, the FEI amounts shown for the years prior to 2015 have been restated to include FEVI and FEW, unless otherwise noted.

Table C-3 summarizes FEI Amalco's overall business profile.

[5] FEI also has a service area in Fort Nelson which is part of the legal entity FEI. The Fort Nelson service area has a separate rate base and rate setting parameters.

[6] Please refer to DBRS's January 2015 FEI's rating report in Appendix A.

Table C-3: Amalgamated FEI's Business Profile[7]

Type of Utility	Local Distribution Company	
Energy Product Offering	Natural gas, biomethane, propane[8]	
Service Area	Mainland, Vancouver Island and Whistler	
Rate Base	$3,661 million	
Sales/Transportation Volumes	176,035 TJ	
Average Number of Customers	970,389	
Net Customer Additions	10,712	
Customer Growth Rate	~1%	
Customer Profile by Demand	TJ	Percentage
Residential	73,067.8	42%
Commercial	55,573.1	32%
Industrial	47,393.6	26%
Customer Profile by Sales Revenue	($000s)	Percentage
Residential	814,408	60%
Commercial	454,626	33%
Industrial	94,386	7%

Notes to Table C-3:

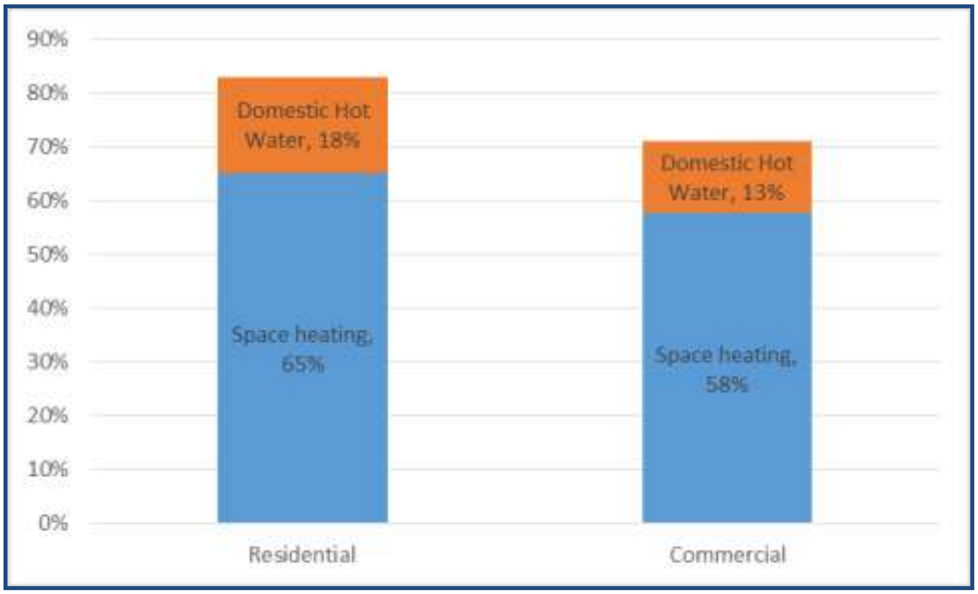
- Residential includes Rate Schedule 1. Commercial includes Rate Schedules 2, 3, 23
- Industrial includes Rate Schedules 4, 5, 6, 7, 22, 25, 27, 46
- With the exception of the rate base amount, all the numbers are for non-bypass customers only. Bypass Transportation volume equals 31,352 TJs and Revenue equals $29,802 thousand

The fact that the majority of FEI's delivery margin revenue is generated from residential customers is significant because FEI faces its greatest challenges[9] in the residential market.

Figure C-1 below demonstrates that in FEI's residential and commercial sectors, space and water heating are the dominant end uses, accounting for about 83 percent and 71 percent of the energy consumption respectively for each sector.

[7] Numbers from FEI's Annual Review for 2015 rates.
[8] FEI serves propane customers in Revelstoke.
[9] For instance the impact of the provincial and local governments' policies on the gradual decline of the natural gas share in the water and space heating markets is more pronounced for the residential sector.

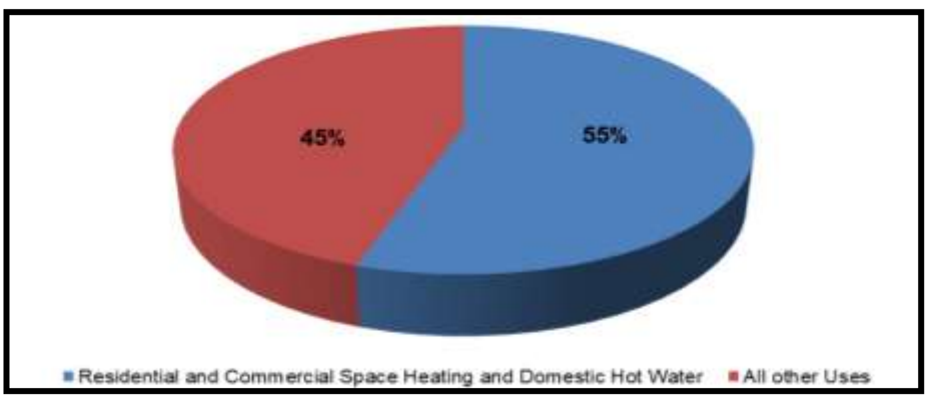
Figure C-1: Residential and Commercial Consumption by End Use (Amalgamated FEI Data)



Source: 2014 Long Term Resource Plan (LTRP)

Thus, the space and water heating market in residential and commercial applications is FEI Amalco's largest market for natural gas, as shown in Figure C-2 below.

Figure C-2: Total Consumption by End Use (Amalgamated FEI Data)



Source: 2014 LTRP

As demonstrated in Figure C-3 below, despite adding residential customers in recent years, amalgamated FEI's total throughput has remained almost the same as in 2005. Indeed, in 2014, amalgamated FEI's normalized demand has experienced a modest decrease compared to the 2012 levels. Industrial throughput variations are one of the large contributors to the annual variations in total normalized throughput. This arises from industrial customers' price sensitivity[10]

[10] For instance, Cement manufacturers exhibit positive cross-price elasticity of demand between natural gas and coal, meaning if the price of natural gas goes up, the demand for coal will increase. For instance a major cement manufacturer in Delta, BC, decreased its consumption from 1.719 PJs in

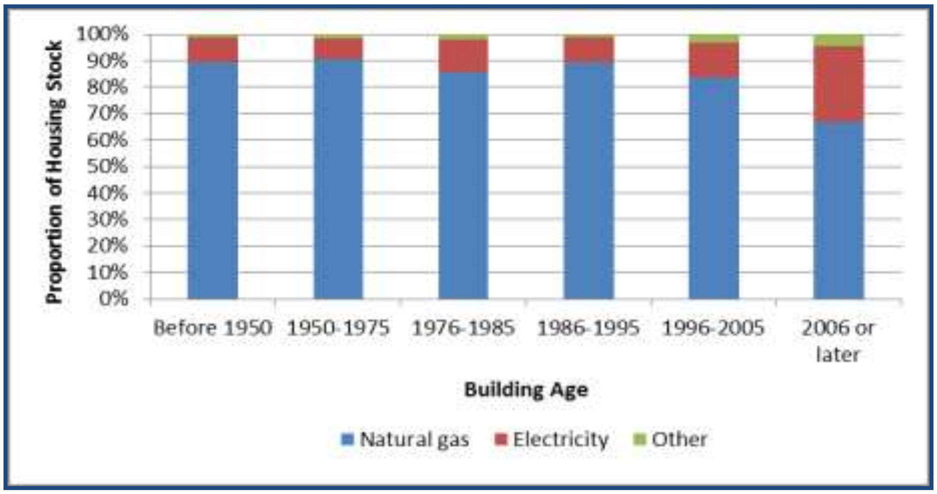
and the effects of business cycles as well as continuing efforts by industrial customers to improve the energy efficiency of their operations. In the long-run, the direction of change in industrial demand will be dependent on the competitiveness of natural gas to alternatives for each industrial customer and the economic conditions of specific industries.

Figure C-3: Amalgamated FEI's Total Throughput (Normalized Throughput vs. Customer Accounts)

The use of natural gas as a main space heating fuel is diminishing while the use of electricity as a main space heating fuel is on the increase. According to the 2012 Residential End-use study (REUS), new homes with gas service are less likely to use natural gas as a main space heating fuel and more likely to use electricity when compared to the stock of natural gas connected homes built prior to 2006. Figure C-4 below illustrates the main space heating fuel trend by dwelling age.

2012 to only 0.244 PJ in 2014 partly due to the increase in natural gas prices between 2012 and 2014. This same customer is now forecasting an increase in usage for 2016.

Figure C-4: Natural Gas Use for Residential Space Heating

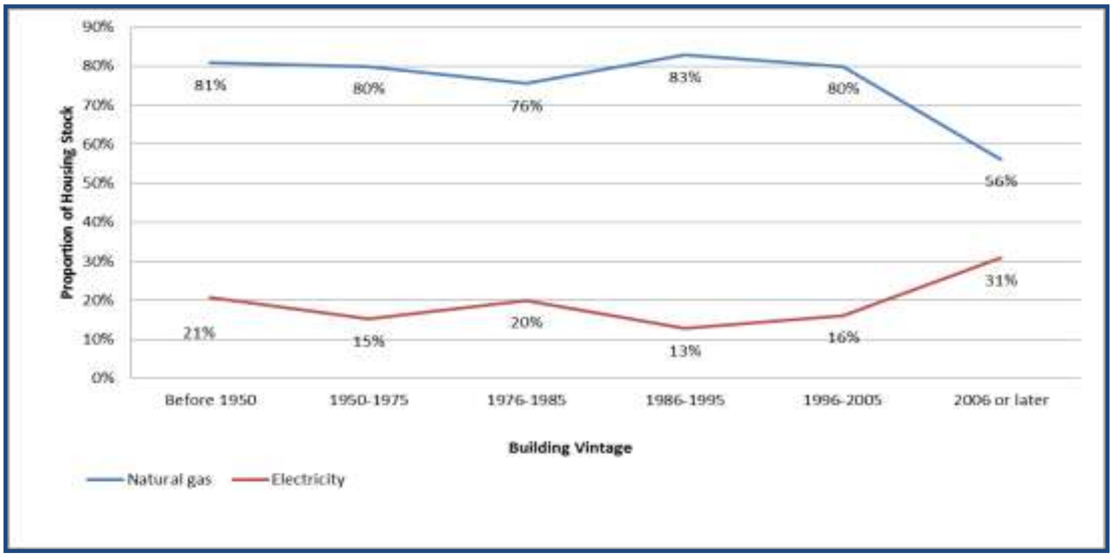


Source: 2012 Residential End-use study

The above trend regarding the energy source used for space heating in housing stock of newer vintage buildings is significant because the share of natural gas heated homes with respect to homes built since 2005 has eroded in light of increasing use of other energy forms, primarily electricity. The percentage of new homes using electricity for space heating in the surveyed population has increased which is consistent with FEI's conclusions in the market shift risk section, namely that FEI continues to lose market share to electricity in the space heating sector. The increasing share of electricity use in space heating is also validated by BC Hydro's 2012 residential end use study.

The same trend is occurring for Domestic Water Heating (DWH), which constitutes the second largest share of natural gas use for residential customers (accounting for approximately 18 percent of total residential natural gas use). According to the 2012 REUS, new homes with gas service are less likely to use natural gas fired DWH and more likely to use electricity compared to the stock of homes built prior to 2006. Figure C-5 below illustrates the trend in DWH fuel by dwelling age. Natural gas use for DWH in new homes has continued to decrease, which demonstrates FEI's continuing challenges in capturing new customers in this sector.

Figure C-5: Trend in Residential Domestic Water Heating Fuel by Dwelling Vintage

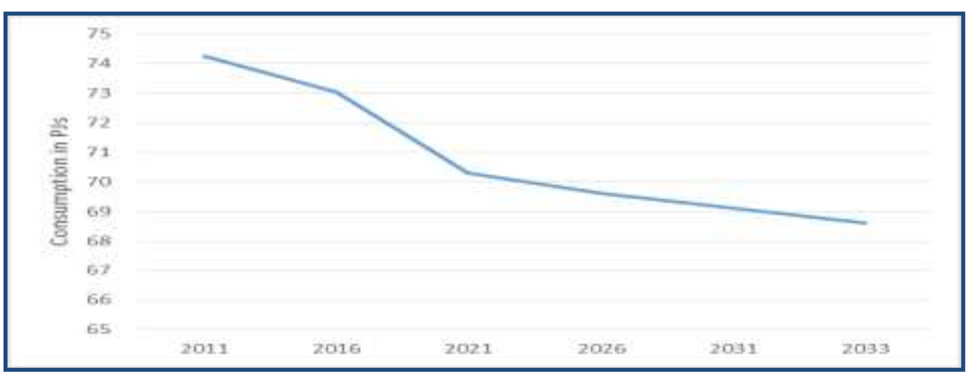


Note: Numbers not additive because some homes may have more than one DWH fuel. Don't knows (DKs) and no responses (NR) have been excluded.

The underlying reasons for the declining trend in natural gas use in residential space and water heating sectors will be further explained in the market shift risk and political risk sections of this Appendix.

As space heating and DHW heating together account for over 80 percent of total residential natural gas consumption, the declining trends discussed above will negatively impact throughput and load growth. Figure C-6 shows the most likely scenario for throughput levels in the residential sector in the years to come.[11]

Figure C-6: Outlook of Amalgamated FEI Residential Throughput Levels



Source: 2014 LTRP – Residential Sector

[11] Note that the scale on the Y axis does not start at zero. This facilitates identification of the data points but makes the slope of the line steeper.

FEI has, in recent years, responded to the changing energy environment in BC and the declining throughput in its core business by undertaking new initiatives. One of those initiatives, Natural Gas for Transportation (NGT), has been identified as a potential new source of load outside of FEI's core market. Table C-4 provides an estimate of the additional volumes forecast to be added to the system as a result of Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) incentive funding and overall efforts to add NGT load to the system.

Table C-4: FEI's NGT Demand Forecast (2015-2017)

Demand Volumes (TJ)	2015	2016	2017
CNG Demand	480	586	616
LNG Demand	435	1,560	3,847
Total NGT Demand	915	2,146	4,463

A continuation of the current low oil prices may hinder FEI's efforts to expand the NGT demand in its service territory.

The addition of NGT volumes is a favourable development for customers in terms of representing a revenue stream. However, they do not materially affect FEI's overall risk profile. For instance, FEI's NGT demand for 2015 is forecast to be around 0.915 PJ which represents less than 1 percent of amalgamated FEI's total throughput. Even if NGT expands to its potential over the next few years, its share of total throughput would remain relatively small.

In addition to the NGT initiative, FEI is also exploring possibilities such as expanding its LNG business for regional export markets, remote communities and power generation[12]. For 2015, this mainly includes the LNG transported from FEI's Tilbury LNG Plant to the Yukon and Northwest Territories for power generation as an alternative to diesel-fuel, with a forecasted annual demand of 87 TJ in 2015.

Along with the above mentioned initiatives, FEI has also been active in the establishment of appropriate frameworks for the addition of potentially large new industrial loads from the Tilbury Phase 1B expansion project and the Eagle Mountain Gas Pipeline (EGP) project for LNG export. Special Direction No. 5 and the subsequent amendment to this direction provided clarity that these investments would be included in the rate base of FEI. FEI has since received approval from the Commission for its large industrial rate schedule 50 tariff, which would apply to these potential large industrial clients. Nevertheless, there is still uncertainty as to whether some of the proposed projects will proceed. FEI expects that these new initiatives and the investment in new infrastructure to serve them would bring some benefits to existing customers, but will not fundamentally change the core business of FEI.

[12] The incremental LNG load for both NGT-related and other LNG demand will be supplied from the Tilbury Phase 1A expansion project which will add an additional 1.1 PJ of LNG storage and about 34,000 GJ per day of liquefaction capacity. For more information regarding the Tilbury expansion project please refer to the Political Risk section.

In summary, FEI remains a natural gas transmission and distribution company with its current core business continuing to be natural gas distribution for space and water heating and will remain so for the foreseeable future even with additions of forecasted NGT and other LNG load that may occur. Attracting and retaining customers in the traditional heating markets remains a critical undertaking, and a key challenge, for FEI.

4. ECONOMIC CONDITIONS

Economic conditions can impact the ability of utilities like FEI to attach new customers and retain customers and maintain throughput levels, in addition to affecting utility access to capital. The current Canadian economic environment continues to be dominated by uncertainty. The recent drop in global oil prices has negatively impacted GDP growth in oil-producing provinces. Other provinces are also impacted indirectly through reduced trade with the oil-producing provinces. Further, economic and financial conditions external to both Canada and BC (i.e. slowdown in economic growth in China, re-emergence of Eurozone crisis) have the potential to affect Canada and BC's economic outlook. Nevertheless, the weaker Canadian dollar and a relatively strong U.S. recovery have the potential to improve export opportunities and partially mitigate some of these challenges. Therefore, compared to 2012, FEI assesses the risk related to economic conditions as similar.

Table C-5 summarizes the changes in leading economic indicators for four jurisdictions across Canada.

Table C-5: Economic Indicators for Four Jurisdictions in Canada (2012 to 2016)

	2012	2013	2014	2015	2016
British Columbia					
Real GDP (% change)	2.4	1.9	2.7	2.2	2.5
Unemployment (%)	6.8	6.6	6.1	6.0	5.8
Housing starts (1000 of units)	27.5	27.1	28.3	26.7	27.1
Alberta					
Real GDP (% change)	4.5	3.8	4.5	-0.9	2.0
Unemployment (%)	4.6	4.6	4.7	5.9	6.1
Housing starts (1000 of units)	33.3	36.1	40.5	36.5	35.9
Ontario					
Real GDP (% change)	1.7	1.3	2.2	2.1	2.5
Unemployment (%)	7.9	7.6	7.3	6.8	6.5
Housing starts (1000 of units)	77.4	60.9	58.3	66.4	68.8
Quebec					
Real GDP (% change)	1.5	1.0	1.4	1.7	2.1
Unemployment (%)	7.7	7.6	7.7	7.5	7.4
Housing starts (1000 of units)	47.2	37.6	38.9	38.2	38.2

Shaded area represents forecast data (2014 real GDP numbers are estimates).
TD Economics, July 2015, retrieved from:
http://www.td.com/document/PDF/economics/qef/ProvincialEconomicForecast_July2015.pdf

Focusing on BC, the real GDP gains in BC are forecast to remain close to the 2012 level. Further, compared to 2012, BC's unemployment rate has slightly improved and is forecast to be around the six percent mark.

Housing starts are an important variable in determining residential customer additions. As seen in Table C-5, BC has the lowest housing starts numbers among major Canadian provinces and is expected to be faced with lower housing starts compared to 2014. Lower projected housing starts can be expected to make it more difficult for FEI to add new customers and throughput.

5. ENERGY PRICE RISK

Energy prices impact utility business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[13] There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity.[14] They include:

- commodity price;
- commodity price volatility; and
- relative installation costs of gas appliances compared to electric appliances.[15]

While commodity price remains a driver of business risk, recent experience suggests that other non-price considerations such as GHG emissions, type of housing mix and the size of new dwellings, customer perceptions and government policy (such as local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, which is discussed in subsequent sections), are taking on greater importance in the decisions of energy consumers.

FEI's assessment is that the overall energy price risk is similar to 2012 levels. While the commodity price risk is slightly lower, price volatility risk is higher than FEI's assessment in 2012 and significantly higher than the level assessed by the Commission in the GCOC Stage 1 proceeding. The risk associated with upfront and installation cost is considered to be similar. Amalgamation had no material impact on energy price risks.

5.1 *COMMODITY PRICE*

This section addresses the commodity price of natural gas and how it affects FEI's competitive position. While natural gas commodity prices are set by the market, electricity prices are heavily influenced by BC Hydro's low embedded costs, making it more difficult for FEI to compete against electricity than gas utilities in some other provinces. Natural gas competitiveness in BC is further challenged by the implementation of the BC carbon tax as well as other non-price factors.

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[13] In this document, the references to electricity as an energy source in British Columbia mainly relate to BC Hydro, which delivers nearly 95 percent of electricity within the province.

[14] This was recognized by the Commission in its 2009 Cost of Capital Decision, p. 36, where the Commission stated: "…natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent".

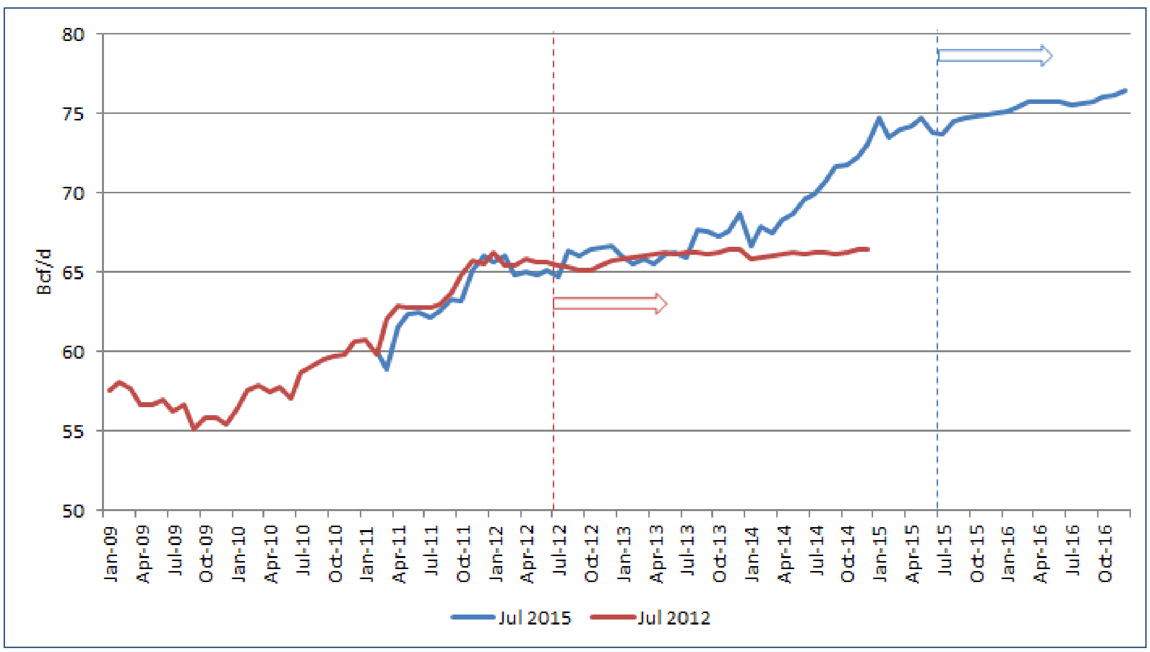
[15] Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulation (i.e. changes in building codes) for gas furnaces such as the requirement to install more costly high efficiency units.

5.1.1 Natural Gas Commodity Prices

In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing the gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America, as well as each utility's operating region. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

As in 2012, the current North American natural gas marketplace continues to be heavily influenced by the abundance of shale gas supply. Continued advances in drilling technology associated with shale gas and the upsurge in associated natural gas supply from increased oil production in the past few years have resulted in an oversupplied natural gas market. U.S. dry gas production has increased significantly since 2012 and reached 73.6 Bcf/d in June 2015 compared to 64.8 Bcf/d in June 2012. Figure C-7 below compares the U.S. dry gas production forecasts from July 2012 and July 2015.

Figure C-7: U.S. Dry Gas Production (Actual and Forecast)[16]



This supply growth has also occurred in BC as natural gas producers have ramped up production to prove up reserves and ensure that supply is confirmed ahead of any potential LNG export demand or other projects that may come online in the future. However, overall the production in the Western Canadian Sedimentary Basin (WCSB) has been flat as declines in Alberta and Saskatchewan production levels have more than offset the increases in BC

[16] EIA - Short-Term Energy Outlook – July 2012 and July 2015.

production. Figure C-8 below shows the recent growth in BC, Alberta and Saskatchewan gas supply within the WCSB[17] over the last five years.[18]

Figure C-8: WCSB Production Growth[19]

The continued growth has helped contribute to low market prices for natural gas on a North American basis. In Northeastern BC, infrastructure development to connect new supply to markets has lagged behind the supply growth resulting in even greater downward pressure on prices at Station 2[20]. Figure C-9 below illustrates the AECO/NIT[21] and Station 2 monthly prices from January 2012 to July 2015. While AECO/NIT prices are higher than they were in 2012, Station 2 prices are currently lower than they averaged in 2012 as the basis differential between AECO/NIT and Station 2 has widened. As discussed in Section 7 of this Appendix, as the

[17] The WCSB is a vast gas producing basin of 1,400,000 square kilometres in western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. U.S. PNW utilities also access portion of their gas supply from the Rockies basin in the United States.

[18] Wood Mackenzie North American Gas Markets Annual Update, December 9, 2014, slide 20.,

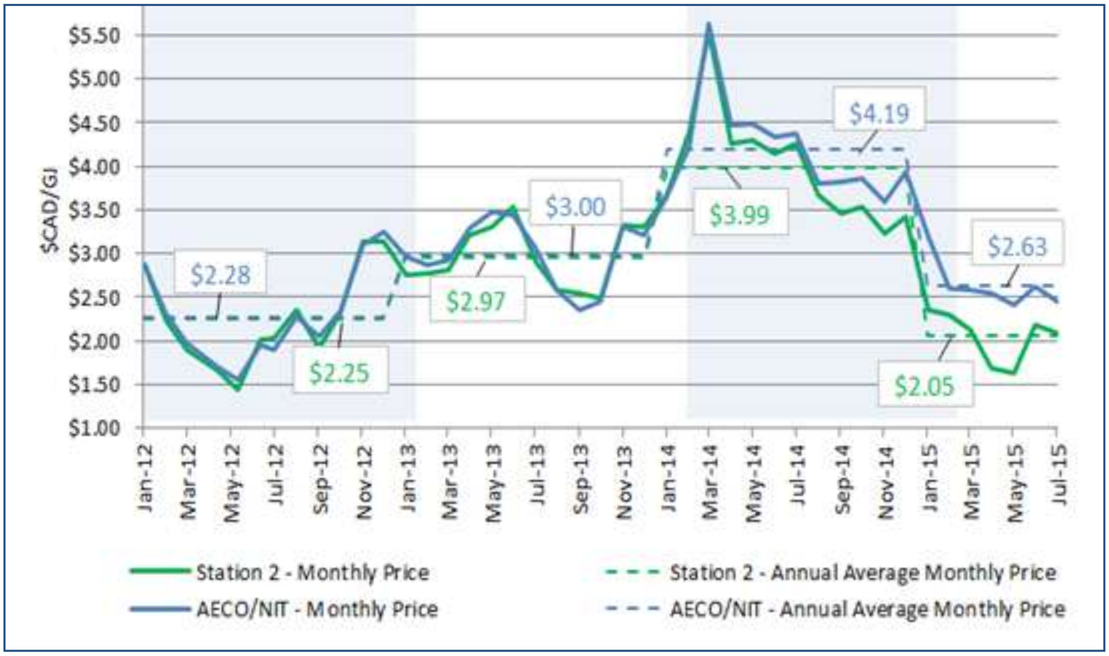
[19] The National Energy Board Short-term Canadian Natural Gas Deliverability 2015-2017 - Energy Market Assessment, Figure C1, Appendix C, June 2015.

[20] Station 2 is the main natural gas trading hub in northern BC. Natural gas produced in northern BC is traded here and then moved to markets further south or east into Alberta and US markets.

[21] AECO/NIT (NOVA Inventory Transfer) is one of the largest natural gas trading hubs in North America, located in Alberta. AECO/NIT prices can be used as a high-level proxy for FEI's commodity supply portfolio costs.

market rebalances (e.g. through greater pipeline connectivity) the differential between Station 2 and AECO/NIT will tighten again.

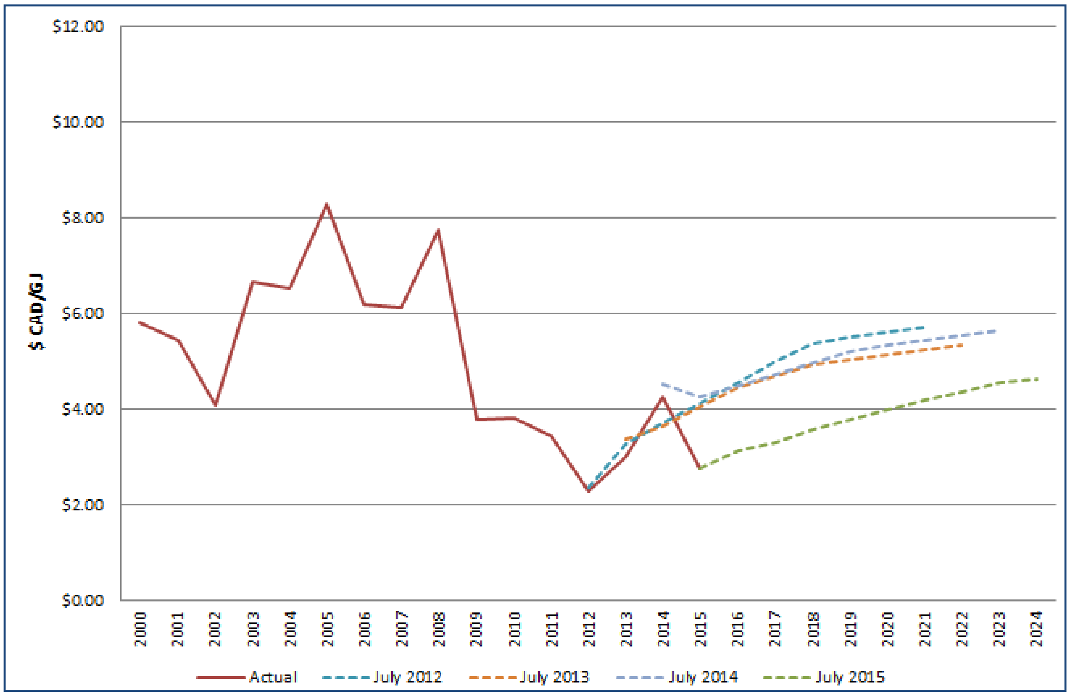
Figure C-9: AECO/NIT and Station 2 Natural Gas Monthly and Annual Average Prices



FEI purchases a mix of AECO/NIT price based monthly supply in Alberta and at Station 2, and daily priced supply at both AECO/NIT and Station 2 to meet its customer requirements. Therefore, when looking at both AECO/NIT and Station 2 prices together, actual market prices are similar in early 2015 to where they were in 2012.

In addition to the continued growth in North American natural gas supply, continued technological improvements have increased well efficiencies and reduced production costs while new industrial demand (including LNG export development) has grown more slowly. As a result, current medium and long term natural gas commodity price forecasts are lower than was predicted in 2012, as illustrated in the following Figure C-10.

Figure C-10: AECO/NIT Historical and Forecast Natural Gas Prices



Source: GLJ Petroleum Consultants[22]

The continued lower level of natural gas prices in recent years has provided incentives and opportunities for the greater use of natural gas across North America. Demand is recovering in the industrial sector after being depressed from the 2008 recession. Additionally, new electricity load powered by natural gas and greater switching from existing coal-fired power plants to natural gas and combined cycle power plants contribute to the increased demand. Increasing exports of U.S. gas to Mexico, as well as the development of emerging markets such as LNG exports and NGT will add to demand over the long run.

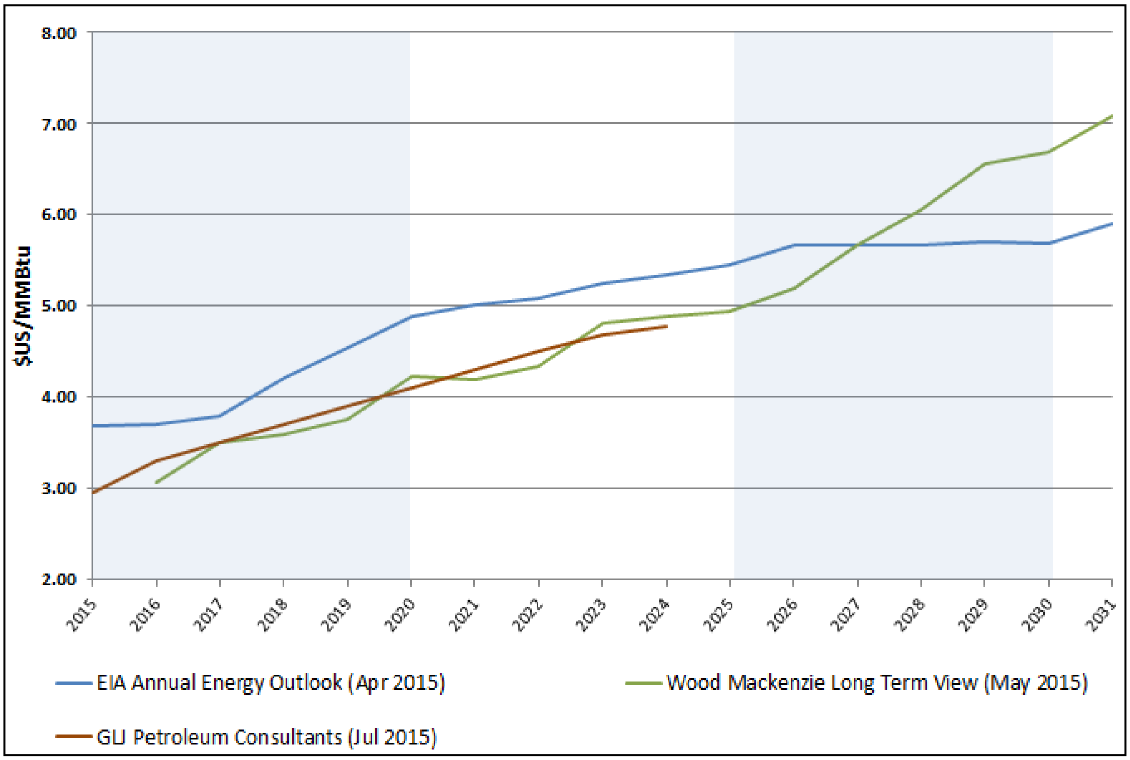
In terms of supply, the recent slowdown in the growth of gas production due to the low market price environment will also help to rebalance the market. Furthermore, with the recent drop in crude oil prices, producers are cutting back on oil production in the coming years, which will impact the associated gas that is produced with oil production. If oil and associated gas production is reduced, this could cut overall gas supply and lead to higher natural gas prices as the average cost to produce gas increases without contribution from liquids-rich associated gas. Figure C-11 below compares long-term price forecasts from different information sources for Henry Hub[23] natural gas that would reflect the expectations of the impact of long-term natural

[22] GLJ Petroleum Consultants Ltd. prepares commodity price and market forecasts after a comprehensive review of information available up to the reported quarter. Information sources include numerous government agencies, industry publications, oil refiners, and natural gas marketers. GLJ publishes these forecast reports every quarter and makes them available at http://www.gljpc.com/commodity-price-forecasts.

[23] Henry Hub is the benchmark gas trading hub for North America and is located in Louisiana.

gas supply and demand fundamentals. The long term forecasts indicated that by 2020, gas prices could be within the $4.00-$5.00 US/MMBtu range. By 2025, analysts forecast that gas prices could be within the $5.00-$5.50 US/MMBtu range.

Figure C-11: Long-Term Henry Hub Natural Gas Price Forecasts (nominal dollars)



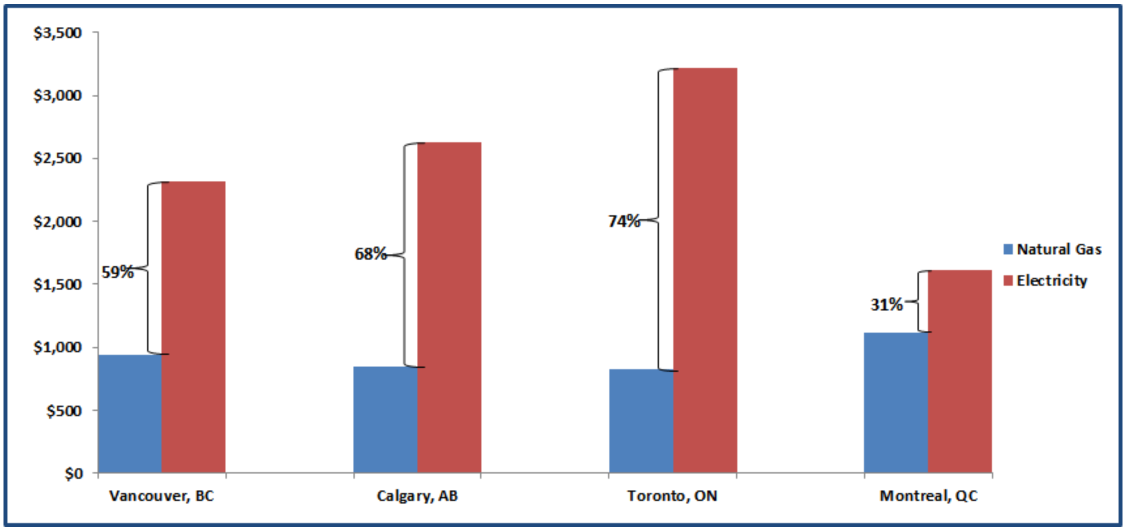
Given the combined factors of similar natural gas current market prices and a lower medium and long term commodity price expectation, FEI assesses the natural gas commodity price risk to be slightly lower compared to 2012.

5.1.2 Electricity Prices

The operating costs advantage of natural gas over electricity has historically been, and continues to be, lower in BC relative to some other jurisdictions, in particular Alberta and Ontario, because of BC Hydro's low electricity prices. Although BC Hydro electricity prices are forecast to increase in the future, FEI will still be faced with the competitive challenges of maintaining and attracting customers which does not exist to the same extent in other provinces.

Figure C-12 shows the extent to which residential electricity rates differ from province to province, with major cities represented. It also demonstrates how the magnitude of the cost difference between electricity and natural gas differs among these jurisdictions. Natural gas has the lowest operating cost advantage over electricity in major cities in British Columbia and Quebec.

Figure C-12: Residential Operating Cost Differences between Natural Gas and Electricity



Assumptions:

- Electricity rates are as per the Hydro-Québec *Comparison of Electricity Prices in Major North American Cities* for rates in effect April 1, 2015
- Natural gas rates are effective as at June 1, 2015 with the exception of Toronto which is effective July 1, 2015
- The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity.
- Estimated bills are calculated based on annual use rate of 90 GJs
- All bills are exclusive of applicable franchise fees and taxes (with the exception of BC Carbon Tax)
- The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use

Even with recent BC Hydro rate increases, the price of electricity is still relatively low in BC compared to major cities in Alberta and Ontario, and is largely reflective of heritage or historical costs of supply. A large percentage of the costs making up BC Hydro's electricity rates are the low embedded costs of the province's hydro generation facilities.

Electricity rates in Quebec, which are also low compared to Alberta and Ontario, are also significantly influenced by relatively low embedded costs. By contrast, in Alberta and Ontario, electricity prices are based on market forces. In Alberta, electricity is generated mainly by the combustion of coal, which is generally more expensive than the historical low-cost hydro generation in British Columbia. Ontario has the most diverse electricity supply mix in Canada, with nuclear being the main source of electricity generation, followed by hydro and then natural gas. Despite the diversity of supply in Ontario, it has higher electricity costs than Quebec and BC.

The narrower operating cost advantage of natural gas over electricity in BC represents a greater challenge for FEI than exists for natural gas utilities in other jurisdictions like Alberta and Ontario. The relatively narrow operating cost advantage makes it more difficult to overcome obstacles to natural gas adoption, such as greater price volatility and higher capital and installation costs, which are discussed below. As the predominant generation source in BC is hydro based, electricity is also perceived more favourably than natural gas.

5.2 *COMMODITY PRICE VOLATILITY*

Natural gas prices are more volatile than electricity prices in BC principally due to the fact that natural gas is market-based, while electricity supply is primarily cost-based. Price volatility is an impediment to attracting and retaining natural gas customers because it can have a negative impact on natural gas rates and can taint consumers' view of using natural gas as a fuel. Greater price volatility can be perceived as leading unavoidably to ever higher prices and rates in the future.[24]

Despite the abundance of shale gas supply in North America, natural gas prices continue to remain volatile and can swing significantly in response to relatively short term market developments. For example, some regions may have limited pipeline or storage infrastructure to meet demand during peak times, which can lead to market price spikes and higher price volatility. BC is one of these regions where infrastructure is limited during high demand periods.

The issue of natural gas price volatility was discussed during the GCOC Stage 1 proceeding. In its decision in that proceeding, the Commission concluded that natural gas prices were projected to be relatively stable out to 2017 based on the forward price curve provided during the proceeding and that this indicated some level of stability over the next few years.[25] A single forward price curve represents prices that could be transacted on a particular date for delivery of gas at a certain point in the future. It does not reflect the potential variability in future prices based on changing market supply and demand factors or market events, and does not reflect where future market prices will ultimately settle.

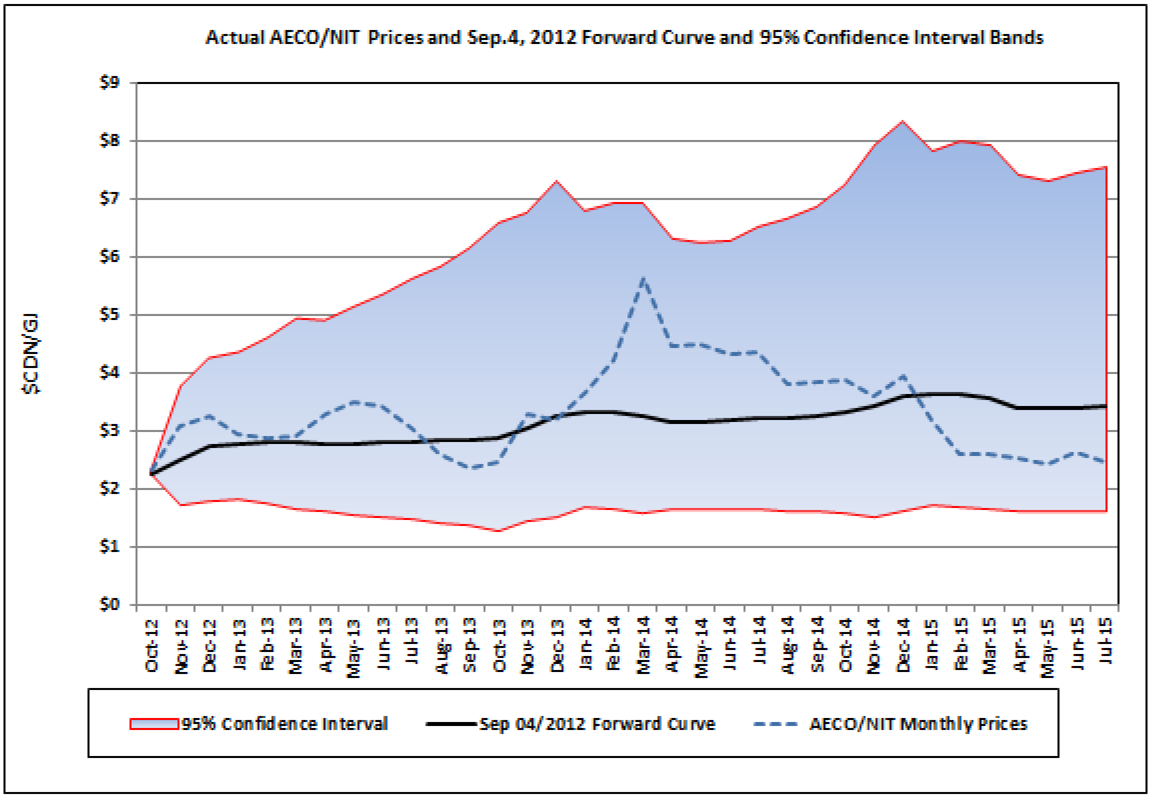
In fact, since the 2012 proceeding, natural gas prices have demonstrated a high degree of volatility, greater than had been expected by FEI and certainly much greater than concluded by the Commission in its decision. The following Figure C-13 shows the September 4, 2012 forward AECO/NIT prices and the 95% confidence level assessed at that time[26] compared to the actual AECO/NIT monthly prices. As illustrated, the actual monthly natural gas prices were not stable and experienced high volatility when compared to the September 4, 2012 forward price curve. Moreover, as discussed further below, daily spot prices experienced much more extreme volatility during this period.

[24] Sampson Research, 2012 FEU Residential End-Use Study - Section 4.2.7.

[25] GCOC Stage 1 Decision May 10, 2013, page 32. The Commission's observation was based on the September 4, 2012 AECO/NIT forward price curve.

[26] The price probability range represents the market's view of the potential range for future gas price movements. This figure's potential range is based on a 95% confidence interval. It is derived using implied volatilities for future months. Implied volatility is the volatility of the price that is assumed by the market based on an option pricing model, such as Black-Scholes.

Figure C-13: AECO/NIT Actual Prices vs. September 4, 2012 Forward Price Curve

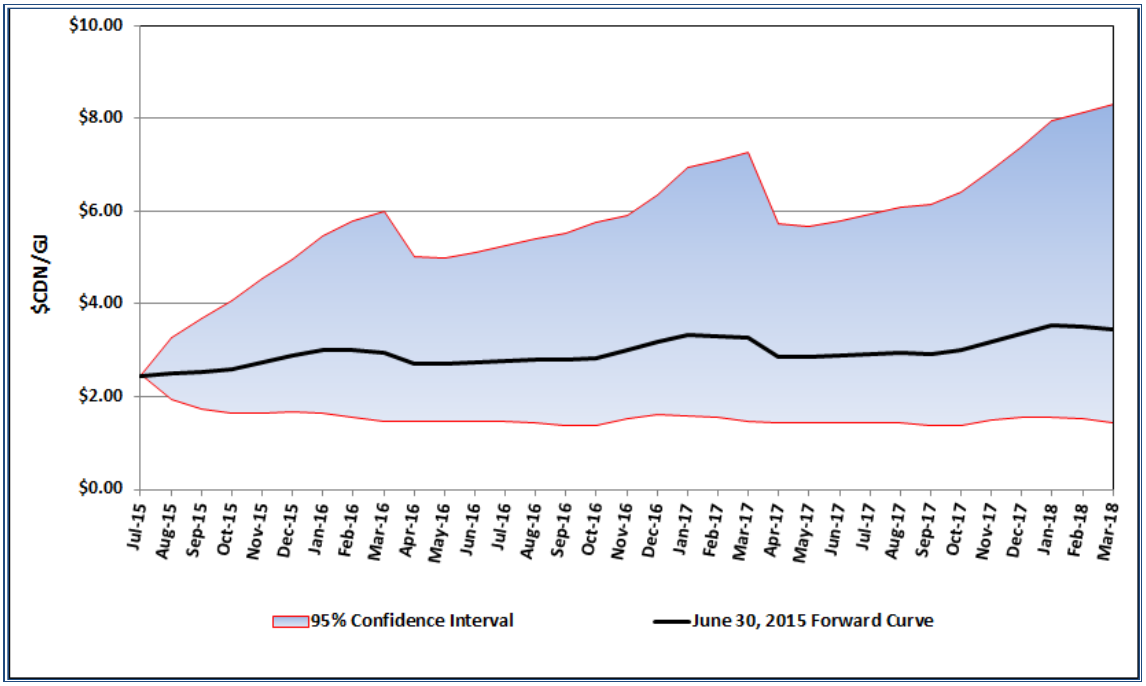


Since 2012, numerous developments in the natural gas market place have caused market prices to continue to swing significantly. In 2012, strong natural gas production, mainly from the development of shale gas, depressed industrial demand, and a warm 2011/12 winter contributed to high gas storage inventory levels and AECO/NIT prices dropped below $2.00/GJ by spring 2012. However, one of the hottest summers on record in 2012 increased gas demand for power generation throughout the summer storage injection season, which helped contract the large storage surplus before winter 2012/13. In winter 2013/14, North America experienced extremely cold weather and gas storage inventory levels dropped to their lowest levels in a decade coming out of that winter. Natural gas monthly prices increased to over $5.50/GJ in March 2014 (and went even higher on a daily pricing basis as shown in Figure C-16) in response to concerns that storage levels would not recover before the next winter. However, the higher prices resulted in lower power generation load which combined with continued growth in gas production helped storage levels to recover before the winter 2014/15. With winter 2014/15 being closer to normal in terms of heating demand for most of North America and production growth continuing, storage levels have been close to historical average levels during 2015. This has resulted in market prices dropping during 2015, with AECO/NIT settling near $2.50/GJ by mid-2015. The following Figure C-14 illustrates how the forward market price curves have shifted since 2012 in response to short term market developments and fluctuations in supply and demand. As the forward curve represents the price at which counterparties are willing to transact at any one time, the curves only represents the price at which FEI could potentially lock in part of its supply portfolio at that time and is not a forecast of what its actual cost of gas will be over that period.

Figure C-14: Changes in AECO/NIT Forward Price Curves

As in 2012, the 95% confidence range for recent forward market gas prices is still wide, reflecting the potential price volatility and continuing uncertainty in where market prices could ultimately settle in the future. This is illustrated in the following Figure C-15.

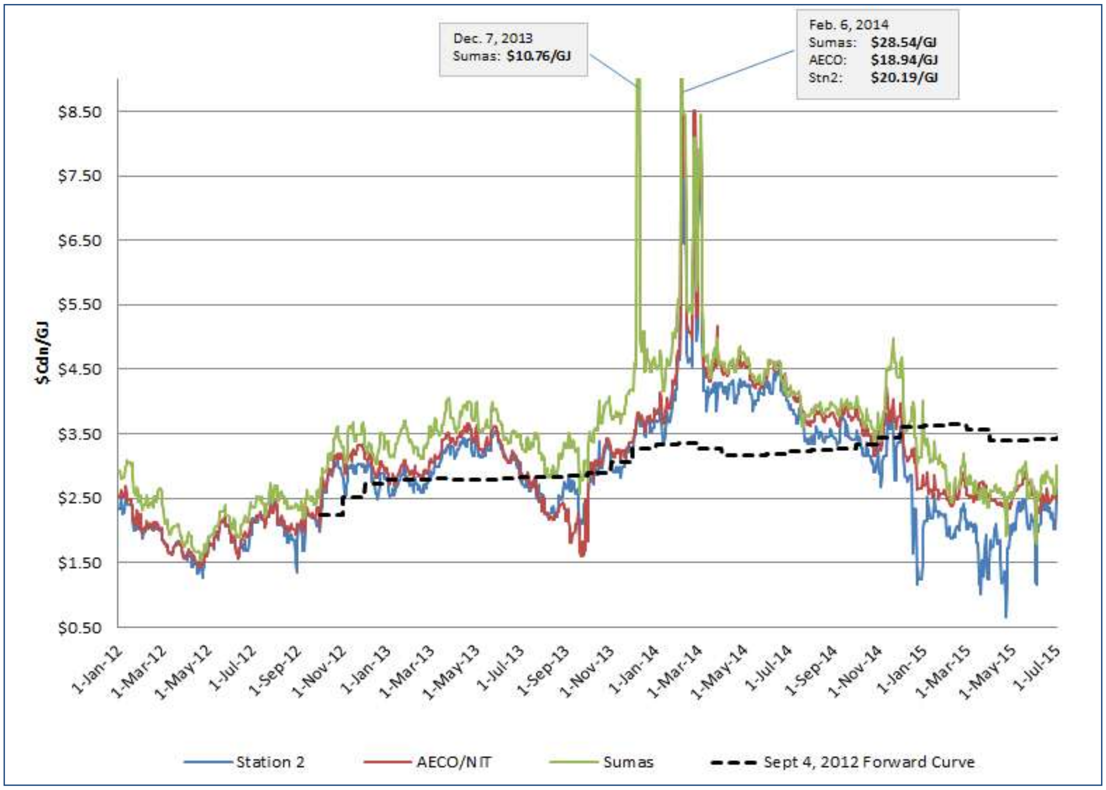
Figure C-15: AECO/NIT June 30, 2015 Forward Price Curve and 95% Confidence Interval Bands



Daily gas prices have been even more volatile than monthly and forward market prices. The following Figure C-16 shows the actual AECO/NIT, Station 2 and Sumas[27] daily prices since 2012 compared to the September 4, 2012 forward curve. The actual daily spot prices have exceeded the price levels from the September 4, 2012 forward curve for most of the time since 2012 and have dropped below that forward curve in 2015.

[27] Sumas is the trading hub located on the BC-Washington border at Huntingdon. It is the main trading hub for BC gas supply moving south to US markets.

Figure C-16: Actual Regional Daily Prices



As illustrated, regional daily gas prices have fluctuated from lows below $1.50/GJ in April 2012 to highs of over $18.00/GJ in February 2014, before falling back to the $2.50/GJ level and below again by June 2015.

During a cold spell in February 2014, unlike in December 2013 where only the Sumas price was disconnected, the AECO/NIT and Station 2 prices (which are most relevant to FEI, given that is where the bulk of FEI's gas commodity is purchased) also spiked due to high gas production freeze-offs[28] and low gas storage inventory levels in Alberta. AECO/NIT and Station 2 prices spiked and settled close to $20.00/GJ and Sumas gas prices settled at over $25.00/GJ. These prices represented the highest market prices ever realized at the AECO/NIT or Station 2 market hub[29].

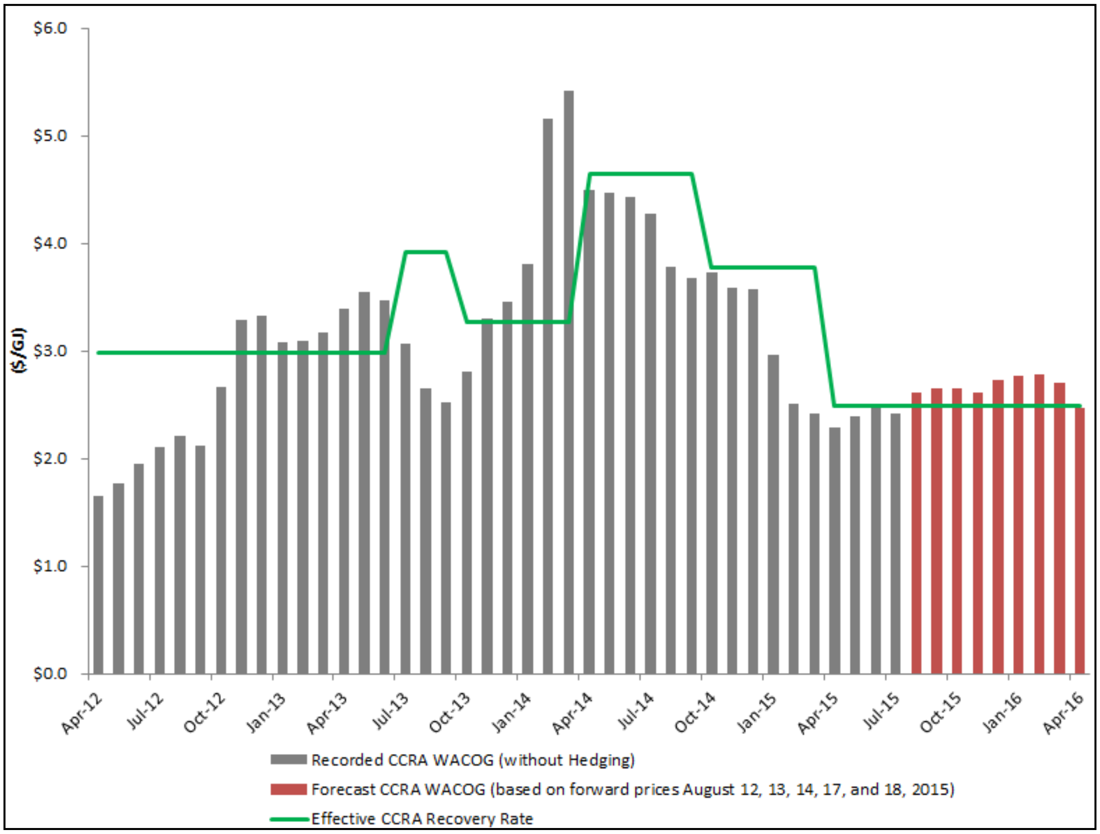
This market price volatility is reflected in FEI's commodity portfolio weighted average cost of gas (WACOG). These are the costs that represent the actual cost of gas purchases and are ultimately recovered from customers through commodity rates. The following Figure C-17

28 Natural gas wellhead freeze-offs happen when outside temperatures drop below freezing in producing fields. If the wellhead is not protected then water and other liquids in the gas can freeze and block the flow of gas.

29 Based on next-day daily settled prices.

illustrates the Commodity Cost Reconciliation Account (CCRA) WACOG and FEI's actual commodity rates over the past three years.

Figure C-17: WACOG vs Commodity Rate (excluding hedging)



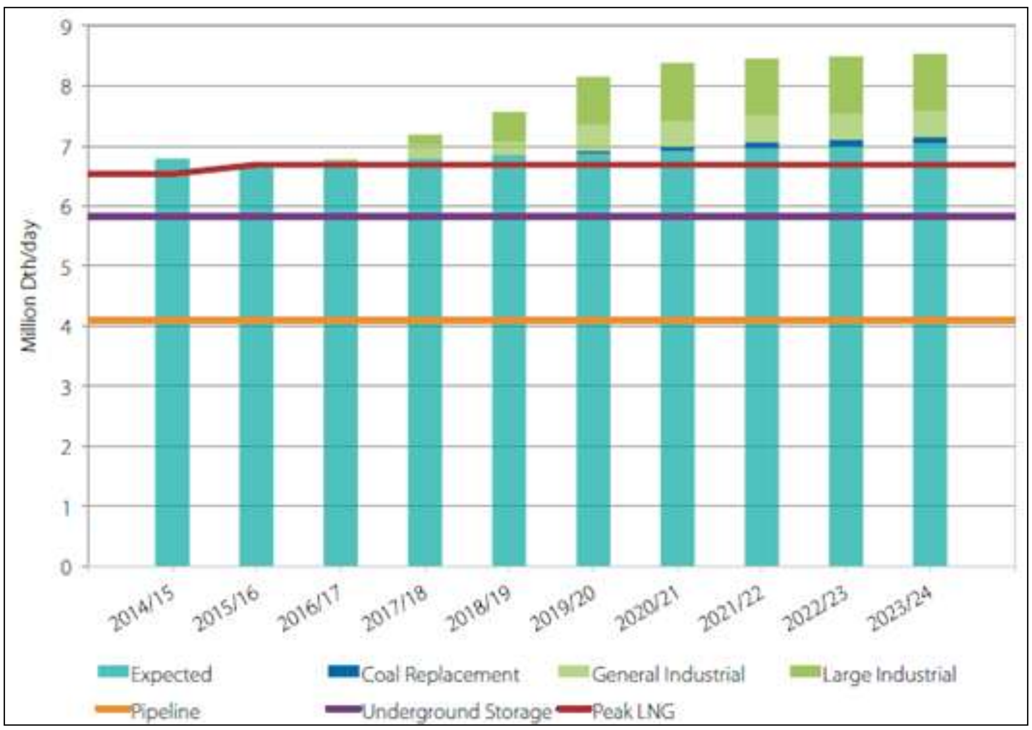
As Figure C-17 above illustrates, similar to the regional gas prices, FEI's WACOG and commodity rate have fluctuated significantly throughout the past three years. FEI's commodity rate has moved from near $3/GJ in 2012 up to almost $5/GJ in 2014 and then back down again to near $2.50/GJ in 2015.

Regional Infrastructure

This regional market price volatility is expected to continue in the future. Regional infrastructure additions can help mitigate some of the regional price disconnection risk; however, these additions require a long time to plan, to secure shipper commitments, to receive regulatory approval, and to construct. The Southern Crossing Pipeline, Mt. Hayes LNG, and Mist and Jackson Prairie storage facilities expansions are examples of regional infrastructure projects that were approved and subsequently constructed to meet growing regional demand that helped to reduce some of the regional constraints. However, further infrastructure may be needed to meet the pace of demand growth in the PNW region if new industrial base load is added.

Although regional residential and commercial market demand growth is expected to be relatively flat, significant new regional demand could come from new projects relating to LNG exports, natural gas power generating plants replacing coal-fired plants and industrial plants. These new projects will require gas supply from Northern BC, Alberta, the US Rockies, using Spectra's T-South pipeline system, NGTL/Foothills/GTN and/or the Northwest Pipeline System to move supply to their facilities. However, this incremental demand requires greater regional pipeline capacity than is currently available. FEI's industrial customers, as well as those in the US PNW, responsible for arranging their own gas supply risk may be left without access to sufficient capacity to meet all of their demand because they may not be able to meet the requirements needed to underwrite the development of new transportation capacity. The Northwest Gas Association (NWGA) publishes an annual energy outlook report every year providing an overview and projection for natural gas supply, demand, and capacity in the PNW region for the upcoming ten years. The following Figure C-18 illustrates NWGA's latest projection of the PNW's peak day resource/demand balance with and without potential accelerated demand if some of the proposed regional projects proceed.

Figure C-18: PNW Accelerated Demand Peak Day Resource/Demand Balance[30]



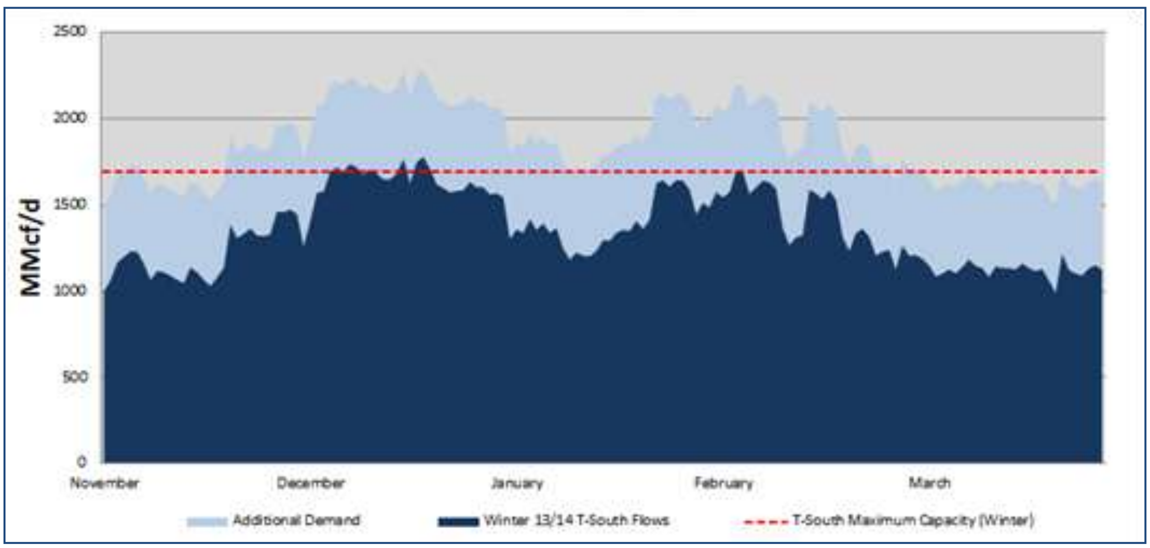
In its accelerated demand peak day scenario, NWGA estimated that there could be an additional 100 MMcf/d of natural gas demand in the PNW region by the end of 2024 due to expanded power generation demand, mainly from coal plant retirements. In addition, general industrial load, including smaller LNG projects, could increase natural gas demand by another

[30] Northwest Gas Association – 2015 Gas Outlook.

435 MMcf/d by the end of 2024. Furthermore, an additional 960 MMcf/d of natural gas demand is being proposed to come online from three recently proposed methanol plants in Washington and Oregon along the I-5 corridor. Depending on how much incremental regional capacity becomes available over time, some current demand that has been depending on interruptible capacity may be left without capacity. The consequence of this outcome would likely result in higher regional spot prices and more price volatility or unserved demand, especially during high demand periods.

The potential for new regional baseload industrial load will result in greater competition for existing pipeline capacity on a year round basis. The following Figure C-19 shows a scenario of what winter 2013/14 T-South flows would look like with an additional 500 MMcf/d of gas demand compared to current pipeline capacity levels and demonstrates that new regional pipeline capacity will be required to support many of these projects.

Figure C-19: T-South Flows vs. Capacity Scenario



While expanding the Spectra T-South system is an option, along with other pipeline solutions, these require long-term shipper commitments and several years to complete. While these proposed projects can also take years to complete, the timing of the completion of such projects does not always align with the required infrastructure, leading to the potential for supply/demand mismatches and price volatility.

Price Risk Management

FEI's current price risk management strategies help to mitigate the impact of regional market price disconnections and regional market price volatility on customer rates. These strategies include the use of commodity rate setting and deferral account mechanisms, the use of natural gas storage and gas supply purchasing strategies that provide supply hub and market pricing diversity. However, FEI continues to operate with limited price risk mitigation strategies that directly impact underlining market prices, such as hedging activities, and therefore FEI's supply portfolio continues to be exposed to market price fluctuations.

In its GCOC Stage 1 Decision, the Commission disagreed with FEI's assertion that it had fewer tools to manage price volatility and that it had expected FEI to consider alternatives for managing market price risk. During the past few years FEI has taken a number of actions in this regard which include the following:

- Research regarding customers' preferences in terms of rate and bill changes and alternative optional commodity rate offerings;
- Removing Huntingdon supply and Sumas price risk from the commodity and midstream supply portfolios;
- Entering into long-term gas supply contracts with BC producers which promote commitment to providing supply to the Station 2 market hub;
- Entering into long-term natural gas storage arrangements;
- Securing Station 2 gas supply with a fixed discount to AECO/NIT pricing;
- Independent consultant review of FEI's price risk management tools and strategies and recommendations for enhancement;
- Submission of the 2014 Price Risk Management Review Report (Review Report) which included a review of FEI's current and available price risk management strategies;
- Discussions with Commission staff regarding the Review Report and approach for stakeholder consultation; and
- Engaging stakeholders in workshop discussions to help determine FEI price risk management objectives and potential strategies going forward.

FEI has just completed a series of workshop discussions with stakeholders and is currently preparing a summary report on findings and recommendations from the stakeholder consultation process. Although stakeholders' views were varied, FEI is hopeful that this process will lead to a better understanding of the market price risk that customers are exposed to, and also to the tools that FEI has or could have to manage market price volatility on behalf of customers.

With regional market price volatility continuing, regional infrastructure becoming more constrained in the future, and limited ability to use additional price risk management tools to manage the underlying gas price volatility from market fluctuations, FEI assesses the risk associated with market price volatility to be higher than 2012 and significantly higher than the Commission's expectations in 2012.

5.3 *UPFRONT AND INSTALLATION COSTS*

Sections 5.1 provided an overview of natural gas price competitiveness on the basis of commodity costs. In this section, the price competitiveness will be analyzed considering the upfront capital cost differences between natural gas and electricity end-use applications (space and water heating).

This analysis is relevant to the challenges faced by FEI in attracting new customers. Builders and developers are the primary decision makers as to what energy source and equipment are used in new construction. Builders and developers are influenced by capital costs, which they must incur up-front and seek to recover in the purchase price. A builder or developer also strives to maximize the useable square footage available from the development to maximize their return on investment. Capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments for certain housing segments. Although the factors considered by developers or builders in installing an energy system will not be uniform in every case, the following excerpt from a 2014 report by IHS CERA[31] noted the influence of up-front capital costs can have on builder and developer decisions:

> *"Finally, builders and landlords generally prefer to install appliances with lower up front capital costs, even though they may have higher operating costs, as builders do not generally have to pay operating costs. For this reason, the builder/landlord preference usually favors the electric appliance over the gas one unless customers request gas"[32].*

Table C-6 below provides the upfront installation (capital) cost difference associated with natural gas versus electricity for an example of a space heating furnace and hot water tank for new construction. In this example, assumptions were based on a single family dwelling (medium size, 3,000 square feet). When considering smaller multi-family dwellings (MFD), such as townhouses and apartment units, the higher capital cost of natural gas further decreases cost competitiveness of natural gas in space and water heating applications.

Table C-6: Upfront and Installation Costs for Space and Water Heating

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electric	$4,435	$1,000
Difference in capital costs	**$4,565**	**$1,000**

Compared to 2012, the difference in upfront capital costs between natural gas and electricity for space heating and water heating purposes has not materially changed. Therefore FEI has

[31] IHS CERA is a U.S. based consulting firm that specializes in advising governments and private companies on energy markets, geopolitics, industry trends, and strategy. CERA has research and consulting staff across the globe and covers the oil, gas, power, and coal markets worldwide.

[32] http://www.fuelingthefuture.org/assets/content/AGF-Fueling-the-Future-Study.pdf, p. IV-14.

assessed that the risk associated with the upfront and installation costs has remained unchanged.

The IHS CERA report also recognizes that even when the operating and upfront capital costs are paid by the same end-user and not the developer and builder, the relatively long pay-back period may be a deterrent to customers:

> *"The natural gas advantage is realized over time as lower fuel costs gradually overcome the higher initial costs, but payback periods may be longer than consumers are willing to accept."*[33]

This statement can be analysed by combining the effects of upfront and installation costs with the operating costs. As demonstrated in Table C-7, the difference in upfront capital costs between gas and electric means that over the life of the appliance the operating cost advantage between natural gas and electricity would have to be at least $13.84/GJ for space heating and $5.25/GJ for water heating for the installation of the natural gas rather than the electric equipment to be economic for the consumer.

The difference in unit capital costs between natural gas and electricity is larger than what was reflected in the data FEI presented in 2012, particularly for space heating. The increase is explained by the lower energy consumption assumption for space heating[34].

Table C-7: Difference in Costs for Space and Water Heating over Measurable Life[35]

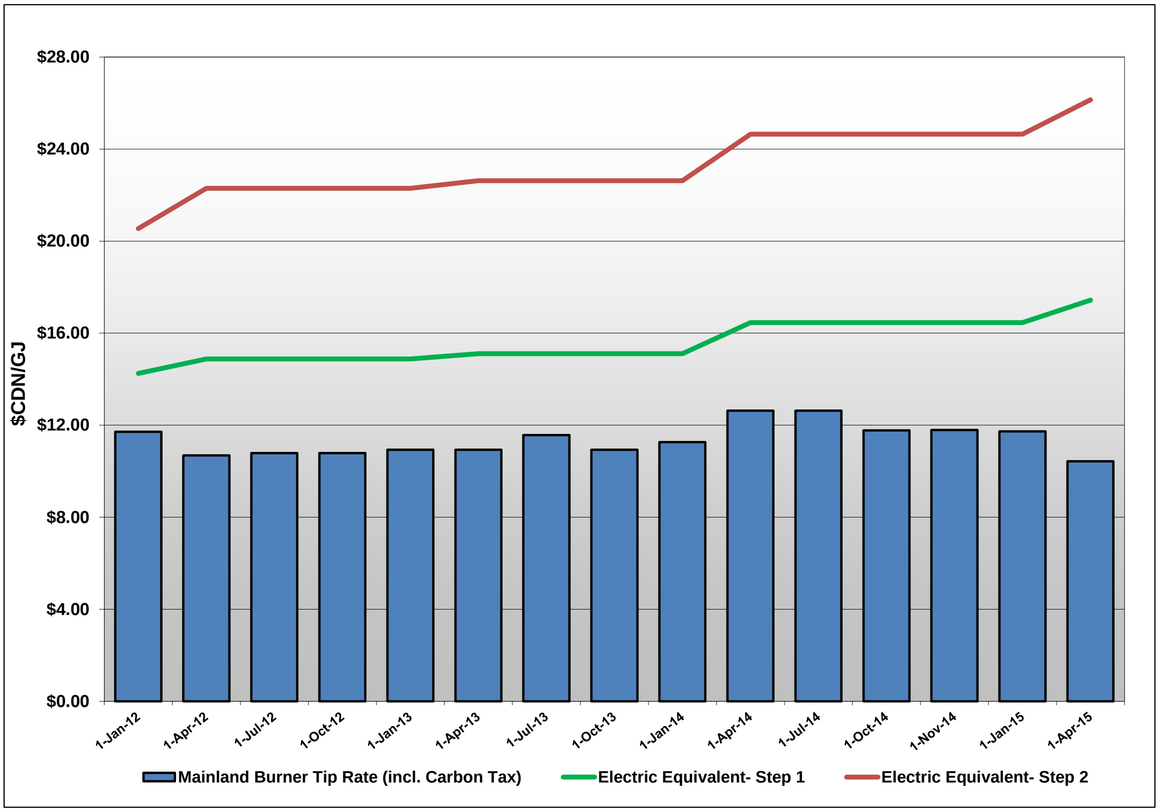
	Space Heating	Water Heating
Difference in capital costs	**$4,565**	**$1,000**
Annual payments for recovery of capital costs	$422	$116
Maintenance costs per year	$100	$0
Total costs per year to pay off difference in capital cost	**$522**	**$116**
Energy consumption (GJ)	38	22
Difference in costs between natural gas and electricity over measureable life ($/GJ)	**$13.84**	**$5.25**

Figures C-20 and C-21 present a historical view of FEI's competitiveness with space heating.[36] As shown in Figure C-20 below, FEI's burner tip rate absent the capital costs (indicative of a

[33] Ibid. p. ES-15.
[34] The consumption assumption is based on a 2014 BC building code compliant home.
[35] Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at approximately 3,000 square feet), interest rate of 6% and the measurable life of 18 years for a natural gas space heating furnace and 13 years for hot water tank. The annual payments to recover the difference in upfront capital costs is calculated based on the present value of an annuity formula where PV of an annuity = annuity * [(1-(1+r)^-n)/r] (r is interest rate and n is the measurable life of the equipment).
[36] FEI burner tip rate presented in the figure includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent (based on an average annual use rate of 90 GJ per year). The Step 1 and Step 2

customer that already has appliances installed) have been below the average rate and Step 1 electric equivalents since 2012.

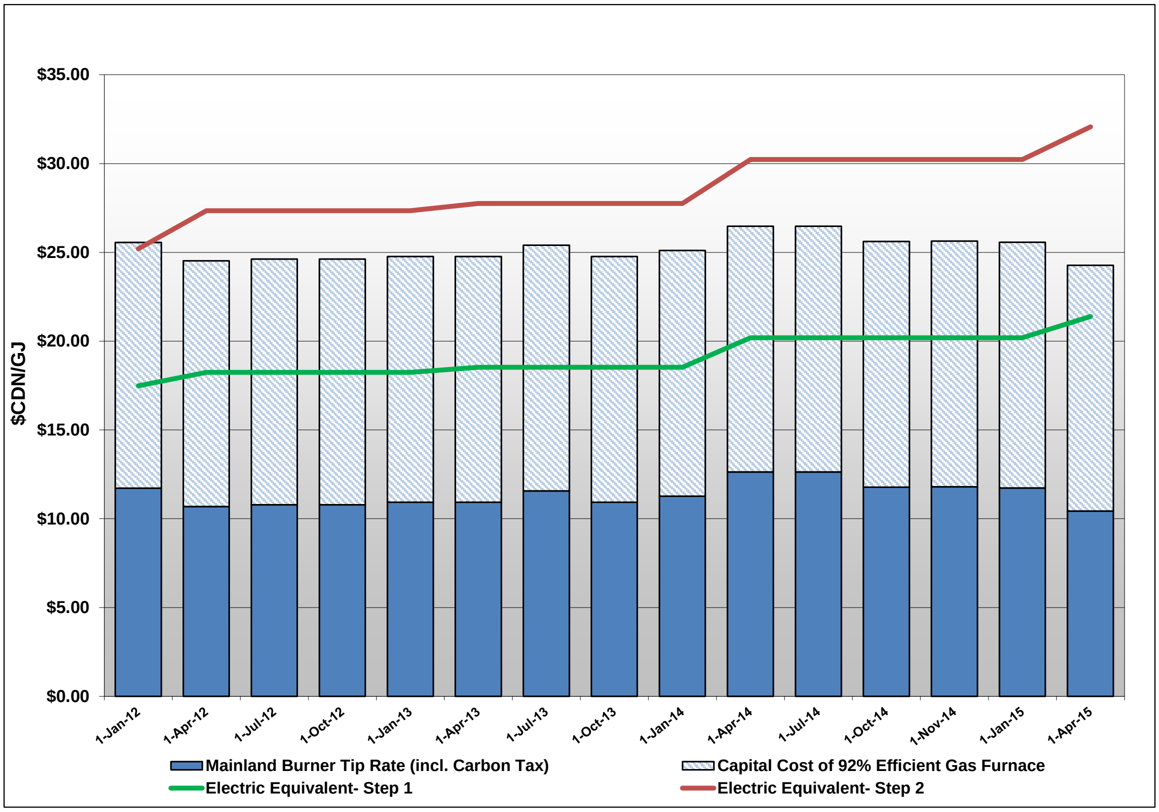
Figure C-20: FEI Mainland Service Territory Space Heating Burner Tip Rate vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces FEI's competitive position against the electric equivalents. From January 2012 to April 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent. Higher total costs of installing gas over electric indicate to the consumer that electricity is the more economical option.

BC Hydro RIB rate electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers in Figure 19. Similarly, the Step 1 and Step 2 electric equivalents have been adjusted using a 92% efficiency to represent the average efficiency level of a new gas fired furnace in Figure 20. The rate the BC Hydro customers ultimately pay is dependent on their actual consumptions (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

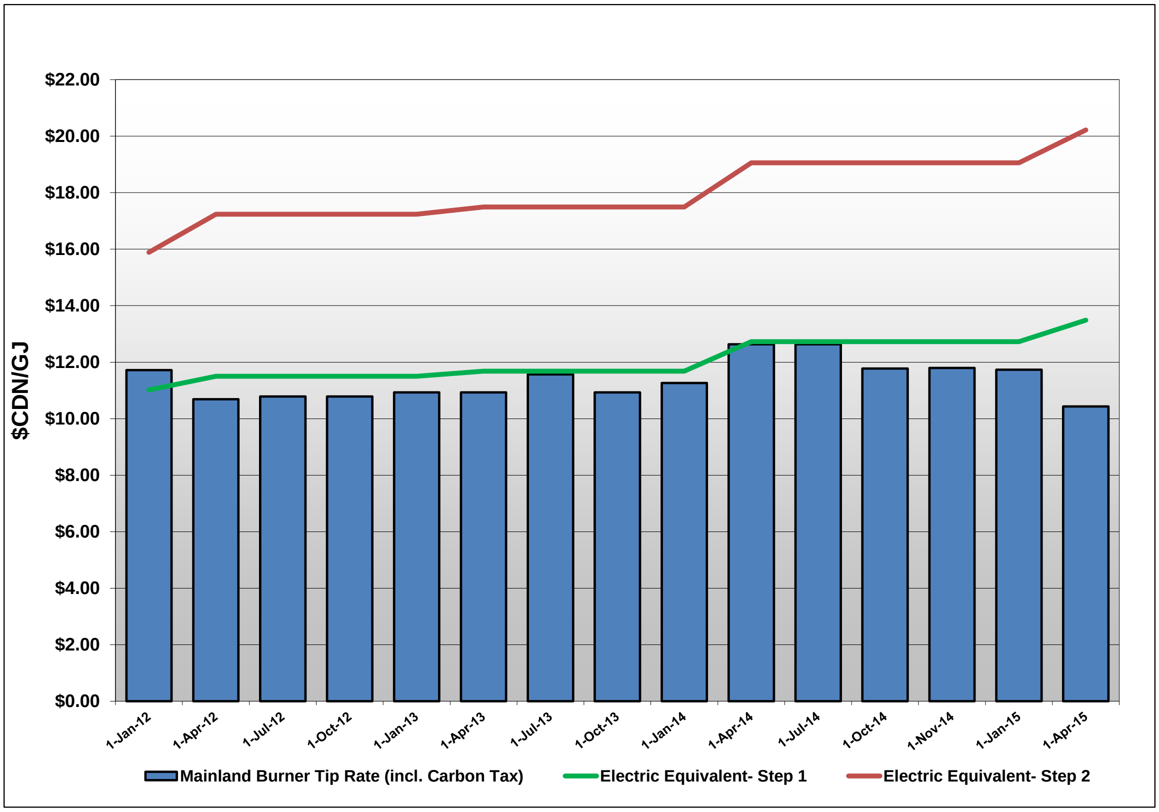
Figure C-21: FEI Mainland Service Territory New Space Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents



Figures C-22 and C-23 below present a historical view of FEI's competitiveness in the water heating market. The FEI burner tip rate includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the Carbon Tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 electric equivalents have been adjusted using a 58 percent efficiency to represent the efficiency level of a current installed gas fired hot water heater for Figure C-22 and 62 percent for Figure C-23 to represent the efficiency level of a newly installed gas fired hot water heater.

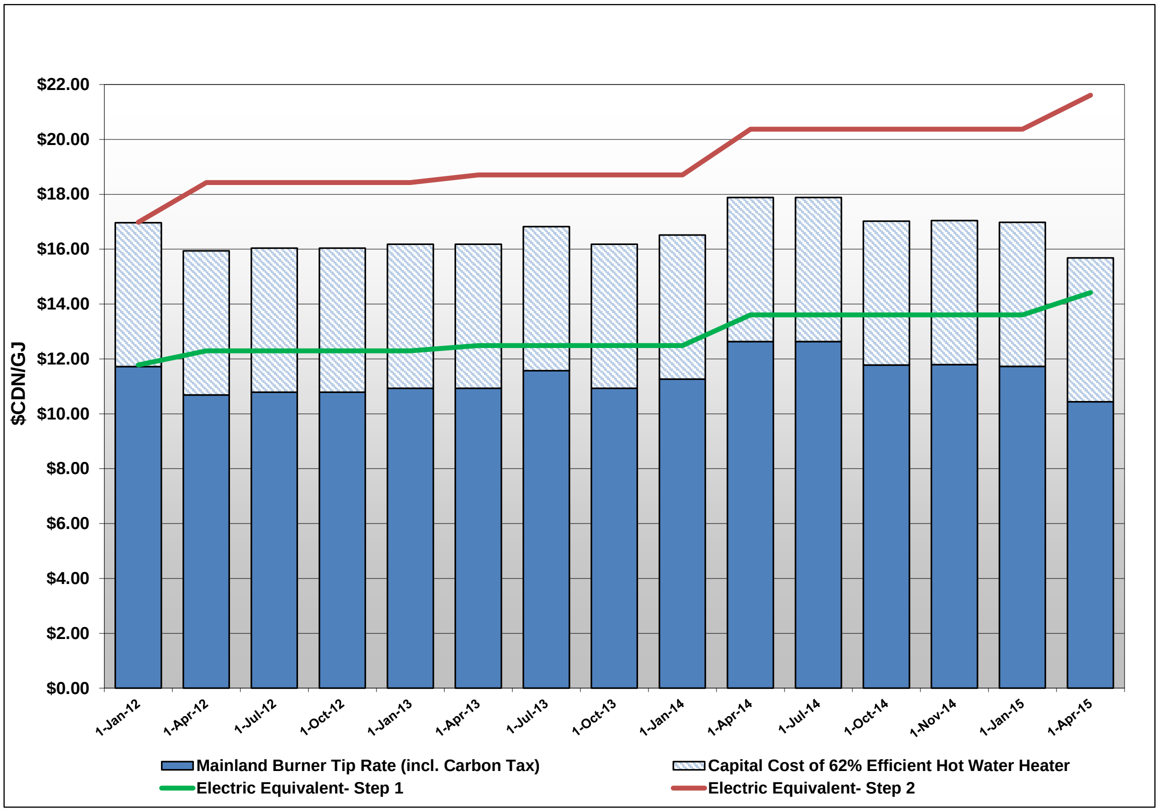
Figure C-22 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the energy equipment is a sunk cost.

Figure C-22: FEI Mainland Service Territory Water Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents



The inclusion of the upfront capital costs associated with the installation of a natural gas hot water heater reduces FEI's competitive position against the electric equivalents. From January 2012 to April 2015, FEI's burner tip rate plus the capital cost put the total cost per GJ above the Step 1 electric equivalent.

Figure C-23: FEI Mainland Service Territory New Water Heating Burner Tip Rate and Capital Cost vs. Electric Equivalents



Until January 1, 2018 when the phase-in to common delivery rates for FEI's three service areas is completed, delivery rates for the Vancouver Island and Whistler service territories remain higher than Mainland delivery rates and therefore the competitiveness of natural gas compared to electricity for these service areas continues to be more challenging than on the Mainland.

In general, with recent increases in electricity prices, the current price competitiveness of natural gas has marginally improved, other things being equal. However, as discussed in the Market Shift Risk and Political Risk sections, the improved price competitiveness of natural gas continues to be muted by non-price factors.

6. MARKET SHIFTS RISK

The choice of energy, and how it is consumed and produced, is influenced by the introduction of new technology and energy forms, changing customer perceptions of energy, and the types of homes being built. Market shifts in these areas continue to pose challenges to FEI's ability to attract and retain customers, and maintain market share and throughput levels.

The available data since the GCOC Stage 1 proceeding has reaffirmed that the declining trend in throughput levels, particularly in the residential sector, is mainly due to two continuing trends: (a) declining annual use trends from existing and new customers mainly caused by the improvements in energy efficiency and conservation as well as smaller average dwelling size; and (b), the weak capture rate in the new construction market in the growing multi-family sector. In following sections, the reasons behind these trends are analyzed in more detail.

6.1 *NEW TECHNOLOGY AND ENERGY FORMS*

FEI's assessment is that new technology and energy forms present similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

In 2012, FEI identified that the adoption of different energy forms in combination with newer technologies represents a challenge to FEI's core business of providing natural gas for space and water heating. FEI addressed the fact that numerous new end-use technologies have entered the energy services marketplace in recent years and will likely continue to do so in the foreseeable future. Developers are responding to their customers' desires for efficiency and innovation by, in some cases, installing newer technology that, while similarly or higher priced than gas equipment, suggests to the buyer that the homes are more advanced and efficient. These houses then command a higher margin for the developer and natural gas is not pursued.

In addition to advancements in both natural gas and electricity-based heating equipment, advancements in renewable thermal energy solutions have emerged to take a small but growing slice of the market. Examples of renewable thermal solutions include air and ground source heat pumps for single family residences; and district energy systems that can employ one or more renewable energy systems such as waste heat from industrial processes, geo-exchange technologies, or biomass solutions, often in combination with natural gas-fired heating solutions. FEI continues to assess how these renewable thermal solutions are impacting natural gas demand and how they are changing the way customers are using natural gas.

The application of existing alternative technologies and the introduction and adoption of new technologies and energy forms has implications for FEI.

- First, renewable thermal energy solutions such as geo-exchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While FEI does not offer these services to its customers, the potential for other third party service providers to do so creates a risk to FEI's annual demand profile.

- Second, the changing landscape of technologies influences codes and regulations and building design and controls, which can have an impact on energy use.

In recent years, non-government organizations such as the Community Energy Association, the Pembina Institute, and Quality Urban Energy Systems of Tomorrow (Quest) are acting as catalysts to spur interest in district energy systems. A Quest progress report published in August of 2013 provided a brief overview of the integrated community energy solutions (ICES) in BC.[37] According to this progress report, more than thirty district (multiple customers) and discrete heating systems were operational in 2013 with more than ten projects in advanced planning, design or approval stages with many more being at the feasibility study stage.

Government is also a factor in the trend towards alternative energy forms. For example, the BC government's infrastructure planning grant program offers grants up to $10,000 to support local government in projects related to the development of sustainable community infrastructure. Along with supporting the development of new technologies and energy forms in residential and commercial sectors, the BC government has also strived to promote the use of alternative fuels and new technologies in the industrial sector. For instance, the 2015 BC provincial budget includes a transitional incentive plan of $22 million paid over a three year period, to encourage the BC cement industry to adopt cleaner fuels and further lower emission intensities. The lower carbon and zero-carbon alternatives the industry is exploring range from waste wood and un-reusable residuals from recycling to bio coal[38]. According to the Canadian Cement Association, the major plants operated by the two major cement manufacturers in BC would use the money to help subsidize the development of alternative fuel sources[39].

Examples of requirements adopted by local governments for developers to consider alternative energy systems are addressed later in the Political Risk section of this Appendix.

Since 2012, a number of regulatory exemptions have been granted to companies that provide new technology and renewable energy services. These exemptions further facilitate the development of these industries and increase their competitiveness against regulated utilities. One such an exemption is the recent Order in Council No. 23 that exempts the "*class of cases where a person, not otherwise a public utility, offers lease agreements or energy supply contracts providing lessees or buyers with solar or wind energy systems or facilities, that could otherwise be purchased on the open market, provided that the value of the installed system including equipment, labour and permits, does not exceed $500,000*"[40]. This will allow entities

[37] Quest BC; August 2013, Integrated Community Energy Solutions Progress Report.
[38] http://www.vancouversun.com/business/resources/Cement+industry+fires+search+alternative+fuels+reduce/10881358/story.html
[39] Coal and natural gas are the main substitute fossil fuels that are used in cement production and an increase in the use of alternative fuels could negatively impact FEI's industrial throughput.
[40] http://www.bcuc.com/Documents/SpecialDirections/2015/01-16-2015_OIC23-VRECExemptionApproval.pdf.

such as Vancouver Renewable Energy Cooperative (VREC) to be exempt from Commission's oversight.

6.2 PERCEPTION OF ENERGY

FEI's assessment is that the perception of energy presents similar risks for FEI Amalco as had been presented for the benchmark utility FEI in the GCOC proceeding.

Historically, customer energy choices tended to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. FEI's customers are more recently also influenced by a desire to use energy efficiently and to adopt lower carbon and renewable energy sources. This creates challenges for natural gas utilities in retaining and attracting heating load, despite the lower natural gas commodity prices currently being experienced. FEI has conducted a number of surveys and studies since the GCOC Stage 1 materials were filed. Figure C-24 summarizes key findings from recent FEI surveys that were undertaken to understand how consumers perceive their home energy options.

Figure C-24: Summary of Customer Perception Research

Alternative Energy Surveys
2009, 2010 and 2012

- Assessed the public's willingness to adopt alternative energy technology, and associated with this, their willingness to pay for them.
- Indicated that while BC residents' awareness and knowledge of alternative energy sources remained steady in 2012 when compared to 2010, they continue to strongly favour incorporating alternative energy sources into new homes. The willingness of BC's residential market to incorporate alternative energy sources has softened in recent years from 69% (2009) to 62% (2013). Barriers identified include: (a) the high capital costs of adoption; and (b) builders and developers cite a lack of voiced demand.

Gas is Good Campaign Assessment
2013 and 2014

- Measured the public's preference for natural gas appliances and their likelihood to consider natural gas appliances in their home buying decision. The study coincided with the Gas is Good advertising campaign which was focused on people looking to buy homes.
- The study showed that over a 12 month period, the percentage of residents receptive to natural gas doubled from 16% to 34%. Over the same period the percentage of respondents who mentioned heating systems as an important factor when buying a new home increased from 3% vs. 10%.

Energy Source Usage Preferences Study
2011 and 2013

- Tracked and measured preferences for future energy sources and attitudes impacting future energy sources.
- A sizeable number of households continue to be unhappy with the energy source they currently use. Furthermore, results show a decided preference for geothermal heat pumps for space heating (50%) compared to a natural gas furnace (43%). In terms of water heating, respondants preferred a tankless water heater (47%). A storage water heater was the second most favorable option (31%). Respondants indicate their energy source preferences for space and water heating are primarily influenced by perceived reliability of the energy source, followed by perceived safety of the energy source.

The differences between preferred and currently used systems can stem from many barriers ranging from financial disincentives to a lack of strong desire for change, to a gap between developers' preferences and end user preferences.

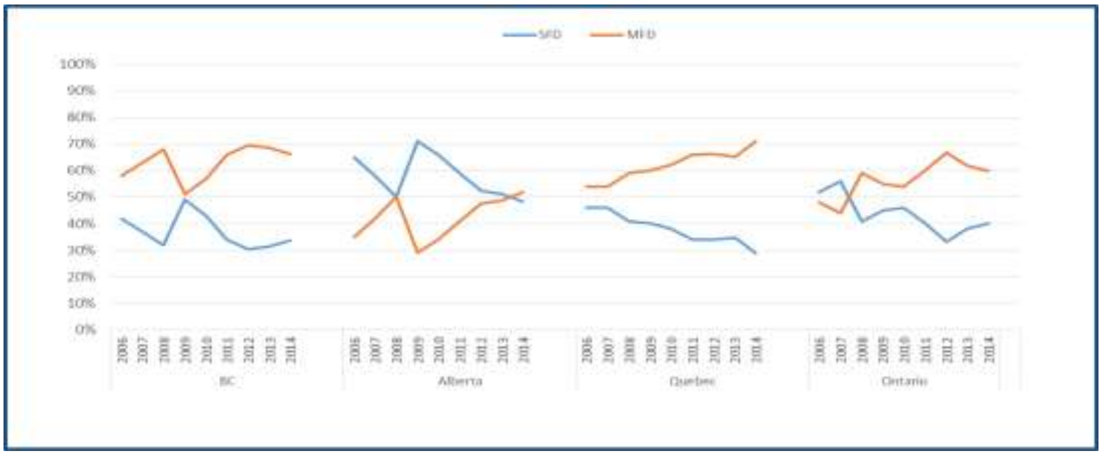
6.3 *HOUSING TYPES*

The market shift in new home development (from single family to multi-family) is adversely impacting natural gas use and capture rates for FEI in a manner similar to what was occurring in 2012. Considering the current lower capture rates in the Vancouver Island service area, amalgamation has had a slightly negative impact on FEI Amalco's overall capture rate. For instance, in the single family dwelling category, amalgamated FEI's capture rate is around 77 percent while FEVI's and non-amalgamated FEI's capture rates were 52 and 84 per cent respectively. Nevertheless, the amalgamation will bring about large rate decreases on

Vancouver Island over the three year phase-in period and may well improve the capture rates. In other words, historical capture rates may not be indicative of capture rates going forward.

As shown in Figure C-25, there continues to be a significant gap between the single-family and multi-family housing starts with close to 70 percent of all housing starts classified as multi-family dwelling.

Figure C-25: Single Dwelling vs. Multi-Family Housing Starts in Selected Canadian Provinces



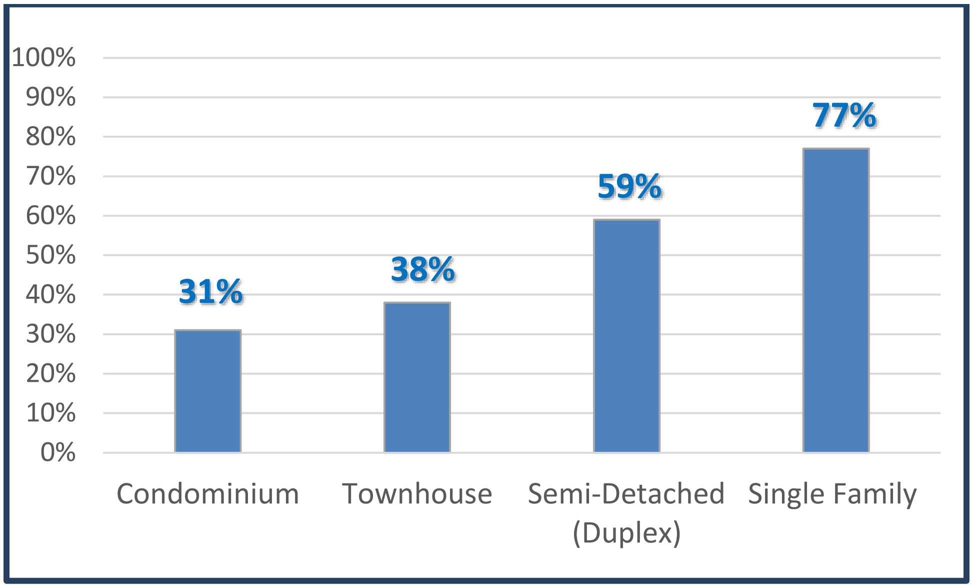
Source: CMHC 2015 Housing Market Outlook, Canada Highlights Edition

There are two key implications for FEI of the housing mix favouring multi-family dwellings.

First, in line with previous studies, the 2012 REUS survey shows that, on average, annual consumption for natural gas is greater in single-family dwellings than in multi-family dwellings. In order to maintain existing throughput levels in an environment where single-family dwelling housing starts are trending lower, natural gas utilities will need to capture more multi-family dwellings to offset the reduced levels of system throughput related to improvements in energy efficiency and technology.

Second, natural gas has a low penetration rate in multi-family dwellings. Figure C-26 shows amalgamated FEI's capture rates by housing types for 2013.

Figure C-26: Amalgamated FEI Capture Rates by Housing Type (2013 data)



The lower capture rate for multi-family dwellings is primarily driven by the unfavorable economics of installing a natural gas application as compared to an electric equivalent.[41] This is especially true for developments where the unit cost plays a primary role in the purchasing decision. In general, developers have a strong incentive to install electric baseboard heating for multi-family dwellings, as opposed to natural gas, given the comparatively high capital costs of natural gas heating appliances, ducting and overall installation costs. Natural gas space heating equipment also occupies valuable living space within a multi-family unit which could otherwise contribute towards a developer's return.

Another significant factor threatening FEI's capture rates (in both residential and commercial sectors) is associated with potential mandatory connection of entire neighborhoods with high population density to district energy systems. For instance, the City of Vancouver has endorsed an application by Creative Energy for a district energy system in North East False Creek and Chinatown, with plans to expand district energy service elsewhere in the City. The City has entered into an agreement with Creative Energy, in which the City commits to passing a mandatory connection bylaw. The bylaw would compel new and renovated buildings in designated neighbourhoods to connect to the Creative Energy district energy system, and thus prevent potential energy consumers in designated areas from choosing natural gas for space and water heating. In its application Creative Energy described that the City of Vancouver was intending to follow this model for the Cambie and Broadway corridors, representing a current 10+ PJs of load for FEI.[42]

[41] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges. page 36.

[42] Note that the COV's application of the same model being employed in the case of Creative Energy would not result in all of this load having to switch over from natural gas. The model is premised on

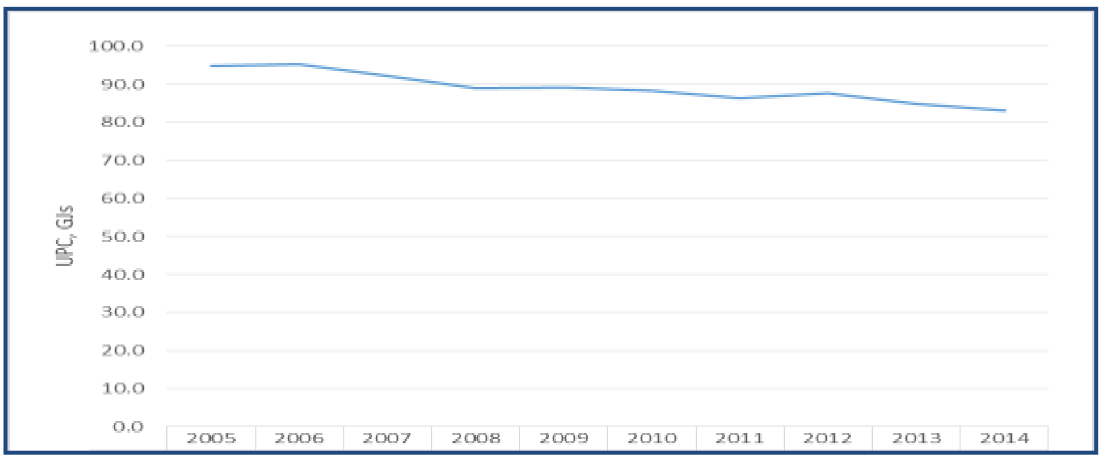
Over the longer term it is expected that electricity will continue to enjoy a greater market share in the multi-family dwelling sector than natural gas.[43]

6.4 *CHANGES IN USE PER CUSTOMER (UPC)*

FEI continues to face declining annual use rates from its existing customers, primarily in the residential sector. This has a direct impact on throughput levels. The residential use per customer (UPC) has been historically higher in the Mainland service area in comparison to the Vancouver Island service area. As such, blending in the lower UPC accounts from Vancouver Island means that the amalgamated FEI UPC is lower than for the pre-amalgamated FEI. On the other hand, FEI's commercial and industrial UPC increases with amalgamation. Similar to capture rates, the full effects of amalgamation on UPC will not be clear until the three year phase-in to common delivery rates has happened. In the intervening period, it is reasonable to assess changes in UPC as presenting similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC proceeding.

As shown in the Figure C-27, amalgamated FEI's residential annual use per customer, or UPC, has declined by more than 11 percent since 2005.

Figure C-27: Amalgamated FEI's Historical Residential Normalized UPC



The decline in UPC is attributable to a variety of factors, including technological advances and energy efficiency improvements, building codes, size and type of homes being built, and type of appliance being installed in these homes. Commodity prices are also expected to influence

new buildings and significant renovations. FEI is providing the 10 PJ figure to give an order of magnitude indication of the importance of these areas for FEI's overall business. It is difficult to predict the rate of renovations and growth.

[43] BC Hydro confirmed this expectation in its 2012 Integrated Resource Plan, stating: "Since row houses and apartments are more likely to be built with electric heat compared to single family homes, the market share for electrically-heated housing is expected to increase." (Appendix 2A, 2011 Electric Load Forecast, page 27).

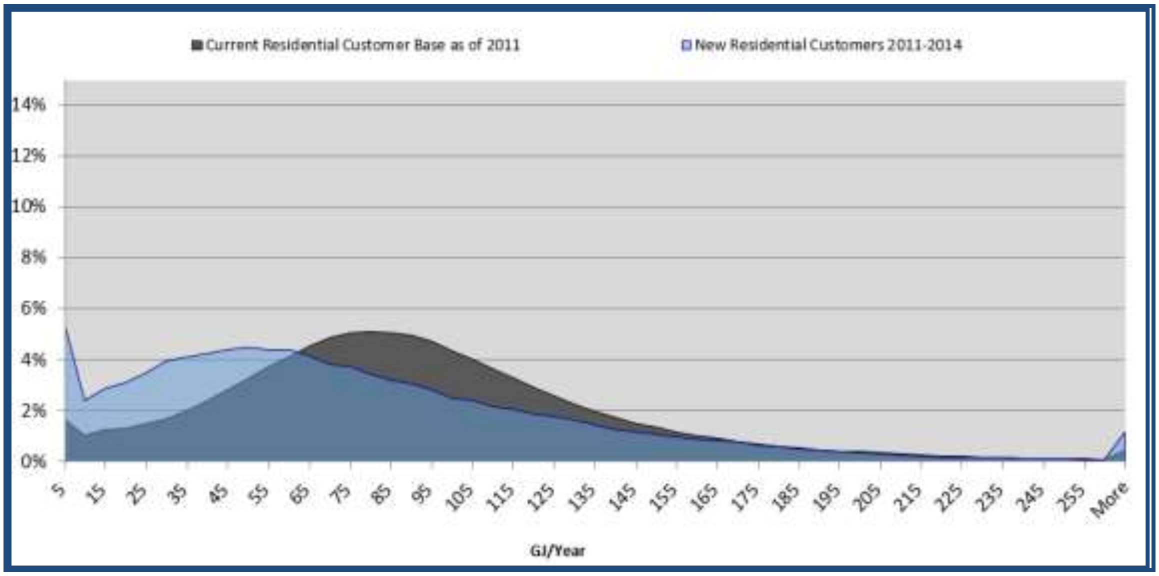
customer use over time; however, actual changes in customer behavior in response to prices are difficult to determine from historical data. As shown in Figure C-28 below, for the residential sector, average use per customer decreased during the period of rising prices but UPC has not rebounded during the low price environment experienced over the last couple of years. This is likely due to the influence of these other factors.

Figure C-28: Amalgamated FEI's Residential UPC and Commodity Price

Short-run price elasticity reflects behavioural changes that a customer may make in response to changes in price, whereas changes in energy-consuming equipment (capital) would be captured in the long-run elasticity. Long-run elasticities are expected to be larger because customers can make adjustments in their capital stock.

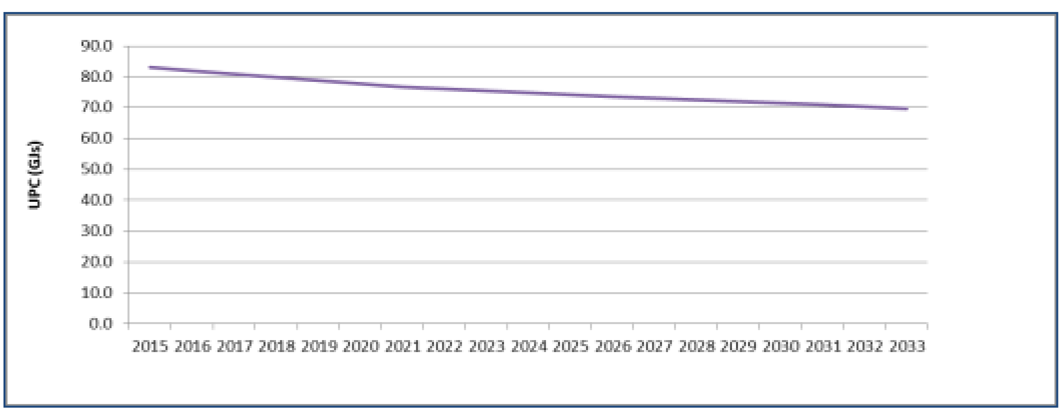
The implication of the research findings is that new customers will have a lower UPC compared to the existing customers as is illustrated in Figure C-29. The frequency distribution curves for the existing and new customers are centered on 84 GJ and 68 GJ, respectively. This means that an existing natural gas residential customer on average consumes 84 GJ in a normal year as compared to a new residential customer who will consume 68 GJ in a normal weather year. This trend in UPC for new customer additions in the residential sector will have long-term impacts on the throughput from this sector.

Figure C-29: Amalgamated FEI's Residential Frequency Distribution



FEI's forecast of the decline in residential use rates is in line with the forecast from its 2014 LTRP. As set out in the LTRP, natural gas consumption in the residential sector will naturally decline by an additional 8 percent from 2011 to 2033 (putting increasing pressure on delivery rates, all else equal), even in the absence of continued demand-side management. FEI also estimated in the LTRP that a total reduction as large as 12 percent on a cumulative basis from 2011 to 2033 may result if new demand-side measures are implemented. Figure C-30 below illustrates the trend of amalgamated FEI's residential use rate for existing and new customers.

Figure C-30: Amalgamated FEI's Residential UPC Forecast

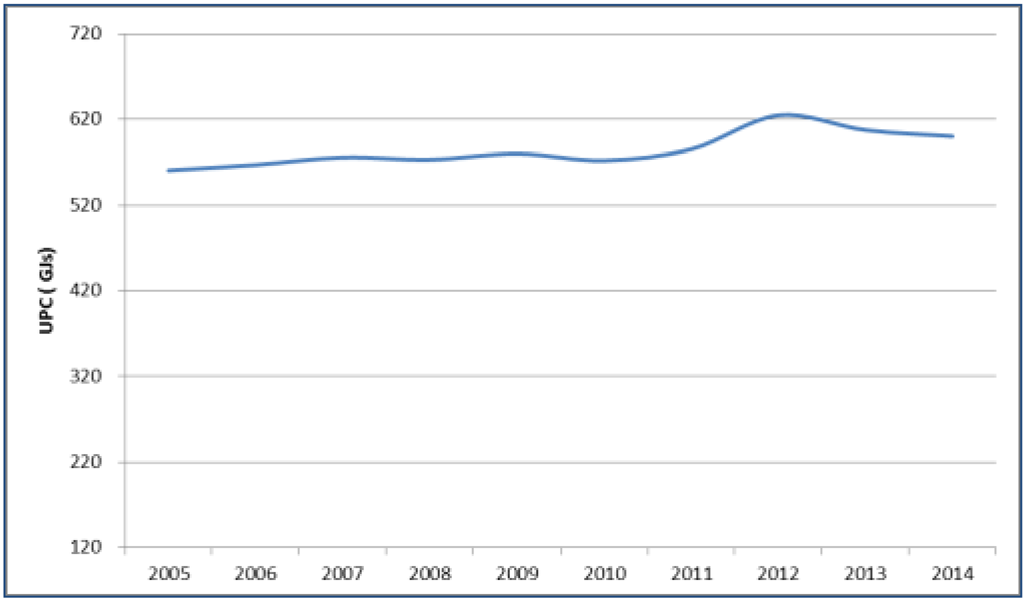


Notes to Figure C-30:

- 2015 forecast is based on Commission Order G-86-15.
- 2016 forecast is based on the proposed forecast in FEI's 2016 Annual Review.

FEI's commercial customers (Rate Schedules 2, 3 and 23) consist of customers from a wide variety of business sectors, as well as from condominiums and multi-family dwellings (greater than 4 units). Since this is a very diverse group of customers there are many factors affecting their natural gas use that may lead to counter-intuitive changes in the overall average commercial use rate. Figure C-31 below shows the historic fluctuations in the annual use rate for the commercial rate class.

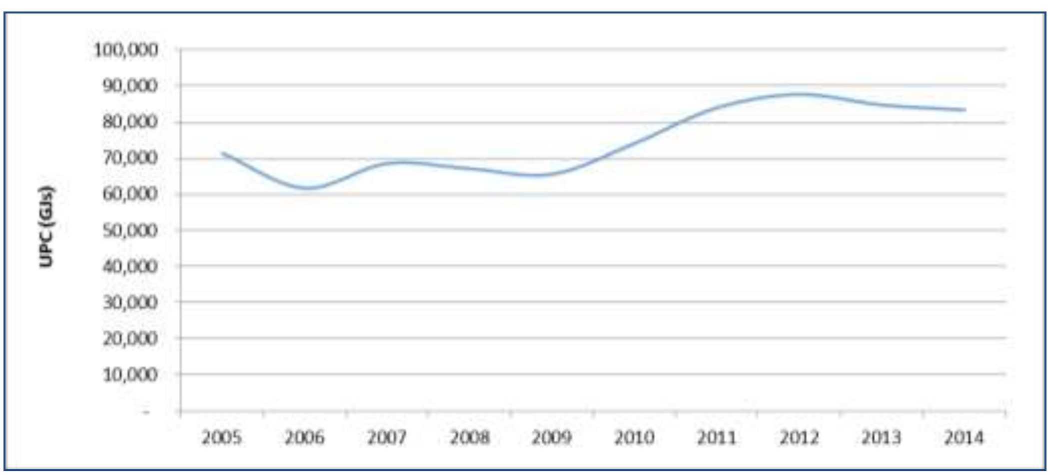
Figure C-31: Amalgamated FEI's Historical Commercial UPC



Forecasting the future use rate for the commercial rate classes is difficult due to high heterogeneity of customers in these rate schedules.

Amalgamated FEI's historical Industrial UPC is displayed in Figure C-32.

Figure C-32: Amalgamated FEI's Historical Industrial UPC



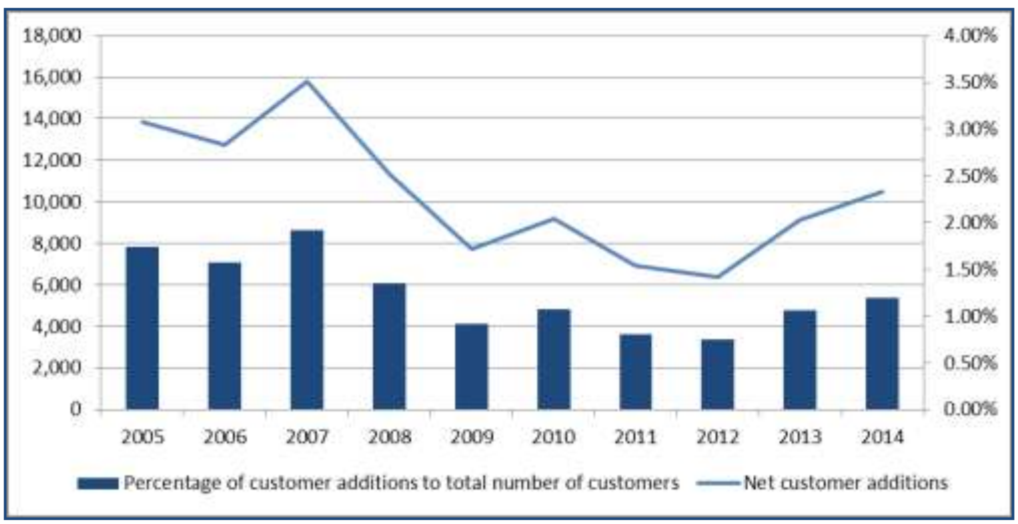
In 2010-2012, FEI Amalco experienced a modest increase in throughput in the Industrial sector as some industrial customers switched fuel to natural gas to take advantage of the lower natural gas prices compared to their alternatives. However, some of this increase was temporary as industrial customers' demand decreased slightly in 2013 and 2014. These small variations in Industrial demand are probably due to the price elasticity of demand for industrial customers as well as their business cycles.

6.5 *CHANGES IN CUSTOMER ADDITIONS*

FEI's ability to manage risk is in part dependent on its ability to attract and retain new customers to offset declines in UPC, and this is proving to be more difficult than it has been historically. These risk factors were also present in 2012. FEI's assessment is that changes in customer additions present similar risks for FEI Amalco as they had presented for the benchmark utility FEI in the GCOC Stage 1 proceeding.

As shown below in Figure C-33, amalgamated FEI's net customer additions increased in 2013 and 2014[44] however this increase was too small to compensate for the declines in the number of customer additions over the 2007-2012 period. FEI added a little over 10,000 residential customers (net of attrition) in 2014, which represents approximately 1.2 percent of the total number of customers in 2014.

Figure C-33: Amalgamated FEI's Residential Customer Additions

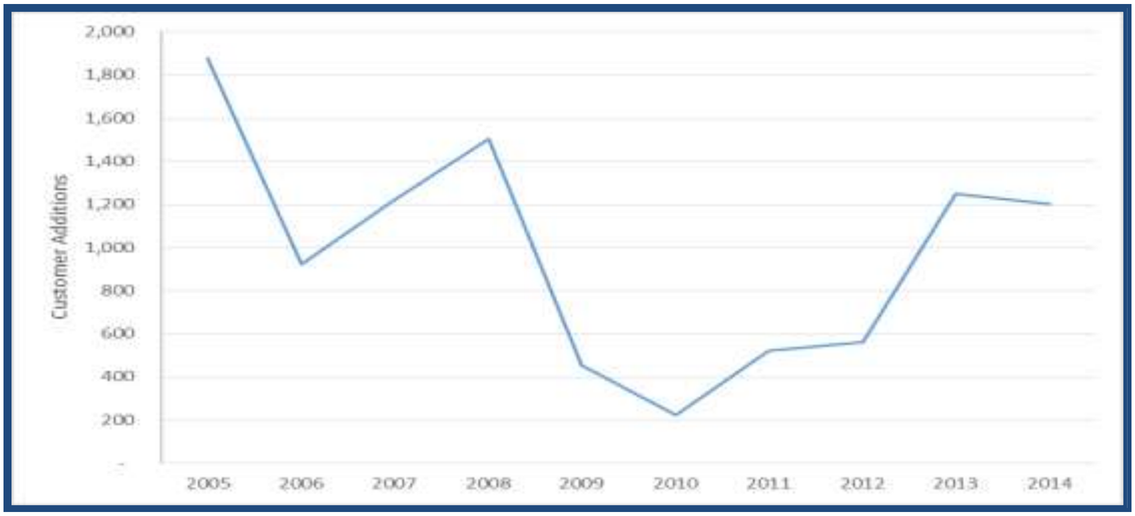


Residential customer additions are influenced by a number of factors, including the new construction market in BC, and the previously-discussed shift in the housing market towards more higher-density housing types where the Company has a low capture rate.

For commercial customers, as demonstrated by Figure C-34, net customer additions are highly volatile and do not exhibit a clear trend.

[44] In 2013 and 2014, FEI undertook an initiative to repatriate customers that had a meter and service line but who had stopped taking service from FEI. This resulted in an increased number of residential as well as commercial net customer additions.

Figure C-34: Amalgamated FEI's Commercial Customer Additions



7. ENERGY SUPPLY RISK

Energy supply risk relates to the physical availability of the commodity and the ability to reliably transport it using third party pipelines to FEI's system for delivery to end-use customers. Supply risk for gas utilities, broadly speaking, includes the possibility of supply interruption, which stems from the degree of reliance on a single supply basin, reliance on a single transportation pipeline, and the availability of regional storage. It also includes the timing and degree of long-term investment in developing and maintaining production, as well as adequate transportation pipeline capacity that is needed to bring production to market.

The analysis of supply risk is separated into two sections: (1) FEI's supply availability, that remains largely unchanged from 2012, and (2) security of supply risk, which has slightly increased compared to that of pre-amalgamation FEI.

7.1 *AVAILABILITY OF SUPPLY*

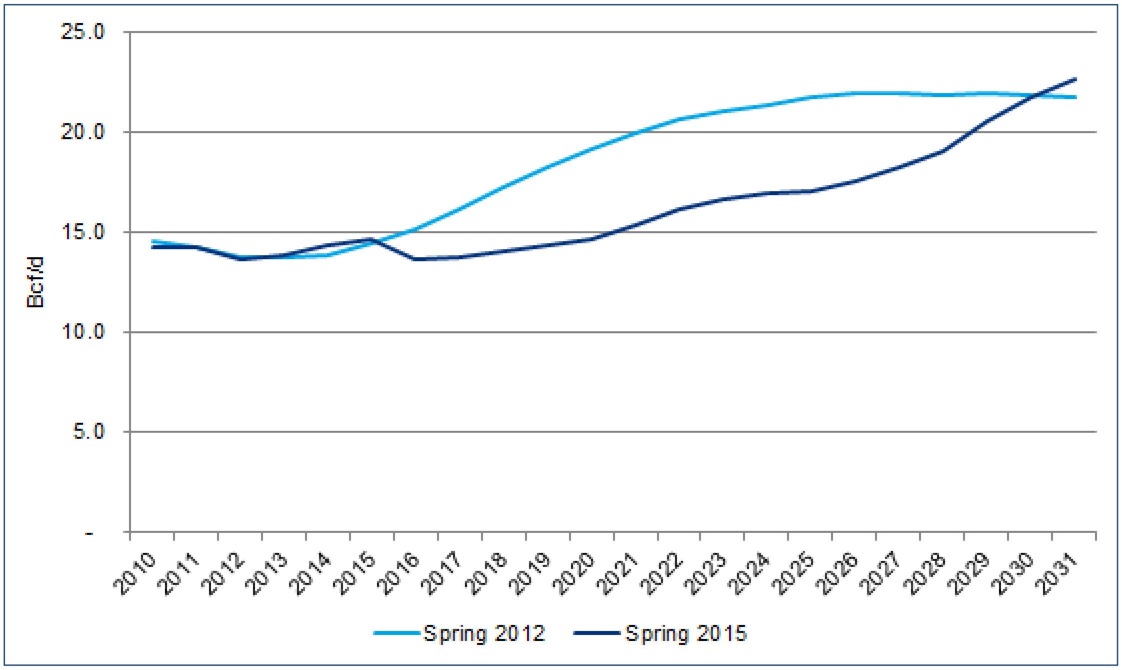
In the oil and gas industry, supply availability is typically separated into upstream activities, referred to as exploration and production (E&P) and midstream activities that include the storage and transportation of energy. Amalgamated FEI continues to source gas supplies from the same market hubs as in 2012. In addition, the integrated operation of the FEI, FEVI, and FEW transmission and distribution systems that existed before amalgamation means that amalgamation itself has had little impact on supply availability for FEI (FEVI and FEW were already connected to FEI's coastal transmission system, and FEVI's Mt. Hayes LNG facility was already used to balance gas supply in FEI's network).

In the next sections, upstream and mid-stream risks of FEI are analyzed in more detail.

7.1.1 Upstream Activities

FEI and other utilities in the U.S. PNW are supplied mainly by natural gas that originates from the WCSB. Figure C-35 illustrates the previous (spring 2012) and recent (spring 2015) forecast levels of supply from the WCSB.

Figure C-35: WCSB Production (Actual and Forecast)[45]



As demonstrated in Figure C-35 the forecast for natural gas production indicates that production is expected to increase steadily after 2016. It also shows that the recent forecast (Spring 2015) has been lowered from the previous forecast (Spring 2012) until the forecasts converge at the end of the forecast period in 2031. This is a reflection of the decrease in gas and oil market prices as well as the potential delay in Alberta oil sands development projects. The increase, albeit slower in the recent forecast, is dependent on rising prices and LNG exports supporting higher drilling levels. The large reserves of shale and tight gas located in northeast BC will not however result in higher production levels unless there are markets for new production. Furthermore, the need for new markets for production from the WCSB has become critical as current production is being pushed from traditional markets in northeastern North America. Traditional eastern markets for WCSB gas are becoming less dependent on WCSB gas because of the availability of and accessibility to a large volume of gas supply from large scale supply sources located in the northeast U.S., such as the Marcellus and Utica shale gas basins. In the future, existing production and increases from new producing areas in the WCSB will also be driven by increased regional demand, including demand from oil sands development and expansion of gas-fired generation load in Alberta. LNG exports will develop if production can be cost effectively connected to overseas export markets. If these new markets do not occur, then the natural gas located in large areas of the WCSB, and especially the significant resource located in the frontier areas of northern BC, will remain trapped. Should this outcome occur, it will be more difficult and costly in the future to secure the natural gas FEI requires.

[45] Wood Mackenzie North America Gas Service.

7.1.2 Midstream (Transportation and Storage)

As described in the GCOC Stage 1 proceeding, even under a production increase scenario in Northeast BC, there is still no guarantee that the incremental production levels would lead to a more cost effective supply for FEI customers. Access and cost are affected by a variety of factors.

Amalgamated FEI continues to contract with third parties such as Spectra, Northwest Pipeline (NWP), and TransCanada's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC for transportation capacity in order to move supply purchased at different market supply hubs, and to complete withdrawals and injections from storage facilities, for delivery to its system. Table C-8 below provides a summary of FEI's main sources of supply as well as the related supply hubs. The FEI's main supply sources have not changed since the GCOC Stage 1 proceeding.

Table C-8: Summary of FEI's Main Sources of Gas Supply

Pipeline name	Supply Source	Main Hub	Level of importance
Spectra's Westcoast Energy Inc. (WEI)	NEBC	Station 2	Approximately 75% of FEI's gas is accessed via West Coast system. Also used for daily balancing via the Aitken Creek storage facility.
NGTL /FoothillsBC	Alberta	AECO/ NIT	Approximately 25% of FEI's gas is accessed via the NGTL and the FoothillsBC system from AECO/NIT. Also provides access to some storage capacity.
Northwest Pipeline	Washington; Oregon storage facilities	Sumas	FEI does not currently contract for Sumas supply but in the future it may provide additional security of supply during winter and peak periods if additional infrastructure is constructed.

As indicated in Table C-8, FEI remains heavily dependent on gas supply from northern BC that is transported on Spectra's WEI pipelines. There are a number of communities served by FEI in north-central BC that are entirely dependent on supply from WEI's T-South because there is no other infrastructure available for transporting natural gas to these locations. Outages or operational issues on WEI's system or in the producing regions can result in supply shortages on FEI's system.

FEI is in competition with utilities in Alberta and the U.S. PNW for storage and transmission capacity. Shorter duration market storage facilities are largely owned by utilities in the U.S. PNW and they have been utilizing an increasing share of those resources for their own use. In addition, the pipeline capacity to the Alberta marketplace from Northeast BC production has expanded considerably in the recent past, which provides optionality for producers to bypass the BC and Station 2 marketplace altogether.

Another critical factor regarding FEI's access to cost effective supply relates to regulatory proceedings in other jurisdictions. There are currently several NGTL and WEI infrastructure and rate design applications that either are or will soon be before the NEB. The decisions regarding these applications could have an impact on the market in western Canada and impact FEI's supply procurement activities. Toll increases on pipelines and competition for BC gas supply from the Alberta marketplace, or Asian markets for LNG, could all put upward pressure on the cost of natural gas for customers in BC.

The NGTL North Montney Project proceeding is an appropriate example for further elaboration on this issue. Although the primary purpose of NGTL's project is to move gas produced in NEBC to serve the LNG export market, NGTL sought to have the project considered an extension of its Alberta system, including the application of its toll methodology. However in its report, the NEB attached several conditions to its recommended approval of the project, including the establishment of separately tolled project facilities unless NGTL comes forward with a new toll proposal. NGTL is expected to come forward with a proposal for a new toll methodology for these facilities that would allow them to be considered an extension of its existing system. NEB approval of such a proposal would impact FEI's ability to continue to access natural gas supply for its customers at competitive market prices, reduce liquidity at the Station 2 hub and increase FEI's cost of holding firm transportation capacity and storage resources. Shippers that today flow gas on T-North and move gas to the Station 2 or Alberta market could alternatively simply bypass the WEI system. Any reduction in the use of T-North and T-South systems will increase the costs to their captive shippers such as FEI[46].

Due to recent regional market changes, there is a new supply risk to customers that rely on Spectra's Westcoast T-South system. New demand from projects either announced or being considered in the Lower Mainland and U.S. PNW have the capability of filling up long term T-South firm capacity.

A significant volume of gas supply serving industrial customers in the Lower Mainland uses the T-South system to flow on an interruptible basis, which means their gas supply is at risk of being cut in the event there is less uncontracted transportation capacity available. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply, or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed. Given that these industrial customers have not made a commitment to hold transportation capacity in the past this may present some challenges for these customers moving forward.

[46] Progress is currently the largest T-North shipper on Westcoast. If Progress were to transfer those volumes to NGTL it could have a significant impact on the utilization and tolls of the T-North and T-South systems.

The supply risk to FEI's customers and other PNW utilities increases if new demand is added and there continues to be a lack of new pipeline transportation capacity. At this time, the only new industrial demand is for FEI's Tilbury LNG facility expansion project. The potential new loads from other potential projects are still pending, so in the short term the risks in terms of physical supply to meet the physical demand remain the same. However, if new load is added to the existing regional pipeline infrastructure, then supply constraints will increase FEI's throughput risk.

7.1.3 Jurisdictional Comparison

The supply and infrastructure for natural gas in BC is significantly different from jurisdictions elsewhere, such as those in Alberta and Ontario. The key differences relate to overall marketplace liquidity, and the number of storage facilities and pipeline companies that operate in the Alberta and Ontario regions compared to BC. In addition, the amount of gas that flows in the Alberta/Ontario systems compared to BC is different.

The Alberta marketplace is a very liquid marketplace on a year round basis as it consists of a wide range of suppliers and resellers who are available on a daily basis to buyers. In addition, gas supply is readily available to buyers and sellers on an intraday basis each day in order to manage gas demand within a utility's operating region. The high level of gas flow in the Alberta market combined with a variety of available storage facilities provides gas supply to customers with no service disruptions in the event of gas plant outages. The close proximity of gas production to market and load centres also reduces the risk of gas supply disruptions for consumers. Although conventional Alberta gas production is declining, the availability of shale gas from BC coupled with significant increases in pipeline connectivity between BC and Alberta is anticipated to maintain the strength and liquidity of the Alberta marketplace.

The natural gas marketplace in Ontario is experiencing change whereby that region has started to benefit from shale gas supply located in close proximity to its operating region from basins such as the Marcellus and Utica. In addition, Ontario has historically benefited from sizable storage and deliverability within close proximity to load and market centres. Ontario's primary trading hub, the Dawn Hub, can access natural gas from the WCSB as well as a number of U.S. supply basins through a variety of pipelines feeding into the Dawn Hub. With the expansion of pipeline capacity, this hub will be able to readily access gas from the Marcellus region. Unlike the BC and PNW marketplace, where storage is limited, approximately 265 PJ of underground gas storage owned and operated by utilities also connect into the Dawn Hub, providing substantial operational flexibility for the region. These differences compared with BC are important because they provide the Alberta and Ontario marketplaces with much more secure access to gas supply and are thus lower risk than the situation in BC.

7.2 *SECURITY OF SUPPLY*

Security of supply relates to FEI's ability to provide gas supply to its core customers under extreme conditions and emergency situations. Compared to the situation set out in the GCOC

Stage 1 Application where the benchmark utility FEI did not include the Vancouver Island and Whistler service areas, amalgamated FEI's supply interruption risks have increased somewhat for the following reasons:

- Both the Vancouver Island and Whistler service areas are downstream of the Mainland Coastal Transmission System. They are dependent on a pipeline system that traverses challenging terrain.
- Vancouver Island is supplied with three twinned submarine crossings ranging from 10.9 to 23.7 km in length. While the probability of a total failure of a submarine crossing is small, there is some additional risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the gas supply that is held in the Mt. Hayes LNG facility has been depleted.
- Whistler is served by the pipeline lateral between Squamish and Whistler, which faces single point of failure risk. Whistler also does not have any on-system storage facilities that can be used to maintain service in emergency situations. The size of the customer base in Whistler is small, limiting the potential impacts of this factor alone on FEI.

8. OPERATING RISK

Operating risk can be defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography and weather. FEI has addressed operating risks in this section with reference to:

- infrastructure integrity;
- third party damages; and
- unexpected events.

There have been no changes to the operating risk facing the facilities in the Mainland service area since 2012. The addition of FEVI and FEW to amalgamated FEI has had no material impact on the risk associated with infrastructure integrity, third party damages and unexpected events because the nature of the risk in all three cases is the same as the Mainland.

8.1 *INFRASTRUCTURE INTEGRITY*

Nearly a quarter of distribution mains and approximately a third of intermediate and transmission pressure pipelines have been in service for more than 45 years. A growing percentage of assets have been in service for more than 45 years. FEI anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

The operating risk presented by assets relates to the ability of service providers to respond to long-term utility infrastructure replacement programs. There are many variables impacting the useful life of underground pipe including pipe material, pipe coating, soil conditions, external interference, corrosion, etc. FEI has several programs in place to monitor, inspect and assess pipe condition and as a result of these assessments has developed longer term capital programs to replace sections of pipe that are reaching the end of their useful life. The primary challenges in terms of executing on infrastructure replacement plans are, firstly, in obtaining regulatory approvals, and secondly, in obtaining project resources to perform the work. These resources would include, among others, a mix of project managers and engineers, planners and field resources. Other natural gas companies in the country as well as other utilities in the province (particularly BC Hydro) are competing for the same resources over similar time periods, potentially driving up service provider costs.

As these trends were already understood in 2012, the Company has assessed infrastructure integrity risk facing amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.2 *THIRD PARTY DAMAGES*

Third party damage refers to a third party either accidentally or deliberately damaging gas assets below ground or above ground. Damage is usually caused by a contractor, municipality or homeowner excavating in the vicinity of gas infrastructure, following unsafe excavation practices and damaging the gas main, service line, or meter which may result in the loss of gas, service interruptions and significant repair costs. The number of incidents of third party damage has been on a decreasing trend since 2006. Deliberate third party damage (vandalism, theft, sabotage, terrorism, etc. usually in relation to above ground facilities) remains a relatively low frequency event in FEI in comparison to excavator third party damage. As this trend was already understood in 2012, the Company has assessed third party damage risk facing amalgamated FEI to be similar to the risk facing the benchmark utility in 2012.

8.3 *UNEXPECTED EVENTS*

Amalgamated FEI has a large radial system that crosses rivers, watersheds, and mountainous and forested terrain. FEI's system is subject to more hazards than operating a natural gas system on the prairies, for example. Natural events contributing to operating risk in BC include floods, washouts, forest fires, land slippage and earthquakes. While the timing of these events is somewhat unpredictable and cyclical in nature, FEI has systems in place to mitigate the impacts of these natural forces. In many cases, proactive emergency planning can further reduce the impacts of these events. However, given that the extent of these natural events remains unpredictable, they pose one of the higher operating risks to FEI.

The magnitude of this risk has not changed materially since 2012.

9. POLITICAL RISK

Political risk can be defined as the potential for government to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, safety regulations and Aboriginal rights. The political landscape is a significant risk factor for FEI.

Based on the above definition, the subsections below focus on climate change policies and legislation, GHG emissions reductions requirements, carbon tax, and Aboriginal rights. Similar to 2012, the BC government's energy policies and legislation do not promote the use of natural gas in FEI's traditional markets (space and water heating) while promoting new initiatives such as NGT and LNG export. Further, local governments have intensified their efforts to promote "green" initiatives that hinder the use of natural gas in space and water heating sectors. A new development since 2012 was the 2014 decision of the Supreme Court of Canada's (SCC) in *Tsilhqot'in Nation v. British Columbia,* which highlighted the risks faced by companies such as FEI with regards to Aboriginal issues. These developments are discussed in more detail in the following sections.

All things considered, it is assessed that amalgamated FEI's political risk is higher than the risk level identified in 2012 for the benchmark utility FEI, primarily due to local government initiatives and the additional uncertainties associated with developments in the law regarding Aboriginal title.

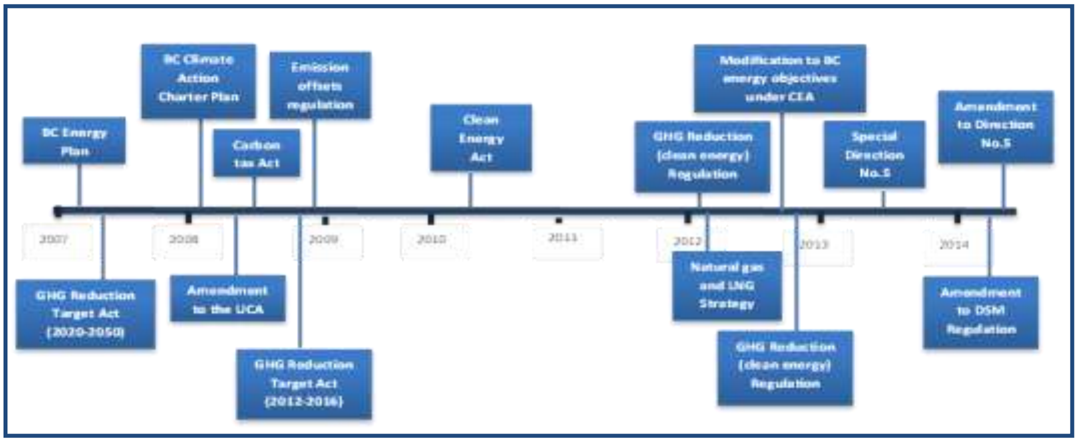
9.1 *PROVINCIAL GOVERNMENT'S ENERGY POLICIES AND LEGISLATION*

The BC government's energy policy and legislation has played a significant role in the risk assessment for FEI in the past. Similar to 2012, the role of natural gas in the BC government's energy policy continues to be focused on the role of natural gas in the transportation market and LNG export, as opposed to FEI's core business of space and water heating. FEI's core business will continue to be in the role of natural gas distribution for space and water heating for the foreseeable future, and it is within this market that FEI faces continuing challenges from policies and legislation that favour other energy sources.

Since 2007, the BC provincial government has enacted a number of significant pieces of legislation in pursuit of its environmental and low carbon economic policies. These policies and related legislation have put substantial pressure on natural gas in its traditional role in providing heat for space and water heating, while creating some opportunities in non-traditional and less significant areas such as natural gas for transportation. The legislation includes ambitious greenhouse gas reduction targets, BC's Carbon Tax Act and the 2010 Clean Energy Act (CEA) which have focused on the role of clean and renewable energy, and energy conservation to meet the energy demands of the province, while at the same time reducing the competitiveness and ultimately the consumption of fossil fuels in BC.

Figure C-36 provides a snapshot of all the recent energy and climate change policies and legislation developed in the province, most of which were discussed in previous cost of capital proceedings.[47]

Figure C-36: Energy Policy and Legislation Timeline



Since FEI filed its evidence in the GCOC Stage 1 proceeding, the BC government has introduced three minor modifications to existing regulations (including a modification to BC energy objectives and amendments to the GGRR and the Demand-side Measures Regulation) and has issued a special direction to the BCUC for development of LNG facilities in BC. Each of these developments is briefly discussed below. They do not represent a change in policy direction since 2012.

9.1.1 Modification to BC Energy Objectives under CEA

In June 2012, there was a modification (highlighted in bold typeface in the following sentence) to British Columbia's energy objectives as defined in section 2(c) of the CEA to "generate at least 93 percent of the electricity in British Columbia, **other than electricity to serve demand from facilities that liquefy natural gas for export by ship**, from clean or renewable resources and to build the infrastructure necessary to transmit that electricity."[48] The change to the designation of natural gas as a source of clean energy for the purpose of LNG export enables production of electricity to fuel the LNG export market without compromising the requirements of the CEA. As a result, natural gas can be used for both liquefaction and as a power-generating fuel in LNG production, which would result in an increase in demand for natural gas in BC, and the potential for higher commodity prices. This modification gave effect to the BC LNG Strategy that had been discussed in the GCOC Stage 1 proceeding.

[47] Please refer to the 2009 ROE and capital structure proceeding as well as the GCOC Stage 1 proceeding for detailed discussions.
[48] British Columbia's Energy Objectives Regulation, B.C. Reg. 234/2012, July 25, 2012.

The power required for FEI's LNG facilities (Tilbury and Mt. Hayes), as well as the proposed Woodfibre LNG facility, is supplied by BC Hydro and therefore this amendment has no impact on natural gas demand in FEI's service territory in the short and medium-term.

9.1.2 Amendment to the GGRR

On November 28, 2013, the BC government amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives, while increasing expenditure caps on items such as grants for safety practices or maintenance facilities, expenditures on stations and a tanker truck load-out facility. This amendment provides FEI with new opportunities in NGT markets; however, the market for the use of natural gas for locomotives and mine haul trucks is in its infancy and should have no significant impact on FEI's throughput in the near-term.

9.1.3 Amendment to the Demand-side Measures Regulation

On July 10, 2014, the provincial government deposited BC Reg 141/2014 (the Amendment) which modified the prior DSM Regulation. The Amendment raised the low income program eligibility threshold and added a deemed list of eligible low income customers. Additionally, it changed the calculation of FEI's cost of energy for the modified total resource test. However, these changes do not result in an expansion of FEI's Energy Efficiency and Conservation spending and have no impact on FEI's risk profile.

9.1.3.1 Special Direction No. 5 to the BCUC

In November 2013, the BC government issued BC Reg 245/2013, Special Direction No. 5 to the Commission under Section 3 of the *Act* (Direction No. 5). Direction No. 5, in its original form, exempted from review expenditures on an expansion of the Tilbury LNG facility up to $400 million, and effectively lowered the LNG dispensing rate to $4.35 per GJ. On December 22, 2014, the BC government deposited BC Reg 265/2014 (Order in Council No. 749) which amended Direction No. 5. The amendment includes the following major components (each of which will be described in more detail below).

(i) ADDITIONAL EXPANSION AT TILBURY LNG FACILITY (PHASE 1B)

The Direction No. 5 amendments expand the Tilbury facility expansion project into two separate phases (1A and 1B) each of which is subject to a cap of $400 million plus AFUDC. Phase 1A is identified as the initial CPCN exemption of $400 million plus AFUDC for the Tilbury LNG facility expansion project as defined in Direction No.5. Phase 1B includes an additional CPCN exemption for a second block of $400 million plus AFUDC for the Tilbury expansion project to provide additional liquefaction capacity but not including storage. The liquefaction capacity of Phase 1B must be 70 percent contracted (on average) over the first 15 years of operation before proceeding with construction. Contracts eligible for inclusion in the 70 percent average calculation must include take-or-pay obligations for at least 10 years and be 10 years or more in duration.

(ii) RATE SCHEDULE 50 – LARGE INDUSTRIAL TRANSPORTATION SERVICE RATE SCHEDULE

The amendment requires the BCUC to approve a new Rate Schedule (RS) 50, designed for large volume firm transportation service for large industrial customers. Among other things, the terms and conditions of this new RS include a minimum of 45 TJ firm daily demand and 15 year contract term. The RS 50 rate structure is designed to recover the costs of incremental capital investments required to serve RS 50 customers with incremental revenue, providing additional contribution to existing natural gas rate payers that will offset the costs associated with the incremental capital.

(iii) TRANSMISSION PROJECT CPCN EXEMPTIONS

The amendment also exempts from the Commission's review the following transmission projects:

- Coastal Transmission System (CTS) capacity expansion projects, including four transmission pressure (TP) projects; namely three projects on the Lower Mainland system (Cape Horn to Coquitlam, Nichol to Port Mann, Nichol to Roebuck), and one on Tilbury Island to increase pipeline capacity into the LNG plant.
- Eagle Mountain Gas Pipeline Project.

(iv) FORTISBC-BC HYDRO LETTER AGREEMENT:

The FortisBC-BC Hydro letter agreement amends several agreements between BC Hydro and FEI and FEVI related to BC Hydro's capacity on the FEI and FEVI systems to deliver gas to Burrard Thermal and the Island Generation (IG) facility in Campbell River. The letter agreement deals with BC Hydro's much-reduced need to transport gas across the FEI system after the impending permanent closure of Burrard Thermal takes place. After that occurs BC Hydro will only require transportation capacity to deliver gas to the IG facility on Vancouver Island. In addition, the letter agreement permits BC Hydro, under certain conditions, to use its delivery capacity to deliver gas to the Woodfibre LNG facility if and when that facility goes into service.

These developments represent a significant addition to FEI's rate base, which in isolation would place upward pressure on rates. It is expected, however, that Tilbury Phase 1A will add throughput and generate counterbalancing benefits through the revenues from LNG sales. As the Tilbury LNG facility project is still in its early stages of development, FEI has assessed the project as currently having no material impact on the business risk of FEI Amalco, either favourable or unfavourable. Over the longer-term, the NGT and LNG markets could help to mitigate rising business risk due to trends in the core business.

9.2 PROVINCIAL GHG EMISSIONS REDUCTIONS AND LOCAL GOVERNMENT INITIATIVES

As has been the case for a number of years, BC continues to be at the forefront amongst those jurisdictions pursuing significant GHG reduction initiatives. The general implications of these provincial policies for FEI's business risk remain consistent with FEI's characterization in the GCOC Stage 1 evidence. Local governments have also been assuming an increasingly active role in GHG emission reduction policy implementations and the codes and recent initiatives by local governments may have significant consequences on FEI's ability to attract new customers and retain existing ones (in some cases local governments have higher GHG emission reduction targets than the provincial government). The increased willingness of local governments to dictate energy choices represents a material increase in risk for FEI.

(i) PROVINCIAL EMISSION REDUCTION TARGETS

The measures put in place in BC, which include a focus on reducing the use of natural gas in heating applications, has a disproportionate impact on BC natural gas utilities. Each of the four provinces examined below has instituted various measures to reduce GHG emissions within its jurisdiction. Table C-9 shows GHG emissions reduction targets in British Columbia, Alberta, Ontario and Quebec. Compared to 2012, these targets have remained unchanged[49].

Table C-9: GHG Emissions Reduction Targets in Four Jurisdictions across Canada

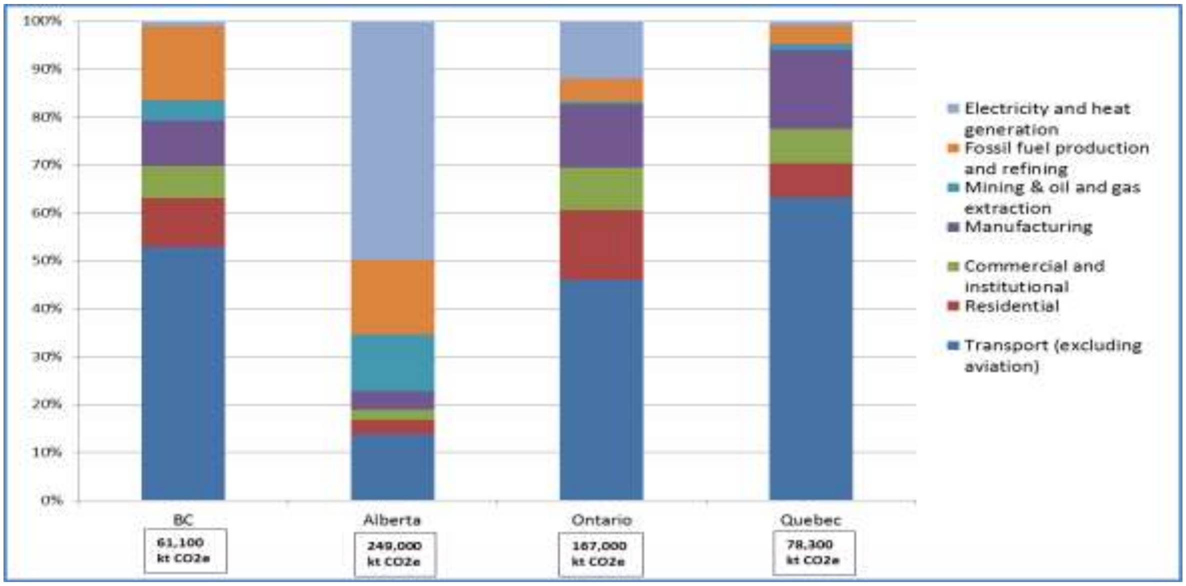
Province	GHG Emissions Reduction Targets
British Columbia	Reduce by 33% below 2007 level by 2020 Reduce by 80% below 2007 level by 2050
Alberta	Reduce by 50 megatonnes below business as usual by 2020 Reduce by 200 megatonnes below business as usual by 2050 (Reduce by 14% below 2005 levels by 2050)
Ontario	Reduce by 15% below 1990 levels by 2020 Reduce by 37% below 1990 levels by 2030 Reduce by 80% below 1990 levels by 2050
Quebec	Reduce by 20% below 1990 levels by 2020

Source : Environment Canada, 2014; Canada's Emission Trends

Furthermore, as Figure C-37 demonstrates, the GHG emissions profile of each province is significantly different from the others.

[49] In May 2015, Ontario Government introduced a new mid-term target while keeping the long-term and short-term targets intact.

Figure C-37: GHG Emissions Profile for Major Energy Sector Categories across Four Jurisdictions in Canada* (2012)



Source: Environment Canada National Inventory Report 1990-2012 data
* The values in boxes underneath each column represent the total GHG emissions in all sectors for 2012 rather than just the major selected categories included in the columns

Differences among the provinces in their GHG emissions profile can lead to different GHG emissions reduction solutions within each province. For instance, as demonstrated, close to 50 percent of Alberta's GHG emissions are related to power and heat generation which is caused by Alberta's traditional reliance on coal fired plants. This implies that a shift from coal to natural gas for electricity generation in Alberta will have the effect of reducing GHG emissions from electricity generation. On the other hand, in provinces such as British Columbia and Quebec with abundant hydro resources available, the GHG emissions in the power and heat production sector are minimal and therefore in order to achieve the GHG emission targets the government must target other areas such as the transportation sector, as well as the residential and commercial sectors.

BC provincial government has recently announced that it is planning to build on the success of its 2008 Climate Action Plan and develop a new "Climate Leadership Plan" to review the options available for reinforcing the provincial efforts to reduce GHG emissions. Although this plan is in its initial development stages (the government is currently seeking comments on its Climate Action Plan Discussion Paper), it creates additional uncertainty.

(ii) LOCAL GOVERNMENTS

Furthermore, legislation continues to require all BC local governments to set GHG reduction targets at the municipal and regional district level. The majority of BC's local governments have signed the Climate Action Charter, pledging to take action to significantly cut both corporate and community-wide greenhouse gas emissions. Local governments can achieve carbon neutrality by reducing emissions, by purchasing carbon offsets to compensate for their greenhouse gas emissions or by developing projects to offset emissions. Such projects may include improving the energy efficiency of local government-owned and operated buildings and vehicle fleets[50].

On September 24, 2008, the province announced the Climate Action Revenue Incentive Program (CARIP) to offset the carbon tax for local governments who have signed the Climate Action Charter. Since 2008, this provincial fund has provided more than $32.5 million to help support B.C. communities' efforts to reduce greenhouse gas emissions and work toward their Climate Action Charter goals (according to the BC government news release on April 22, 2015, communities throughout BC received more than $6.5 million with the latest rounds of grants through this incentive program)[51]. To be eligible for the program, municipalities are required to report annually on the steps they are taking – and progress they have made – to become carbon neutral.

Based on a review of the corporate and community-wide actions[52] reported over 2010, 2011 and 2012, some overall trends regarding local governments' corporate and community-wide effort reduction efforts have emerged[53]. For instance, on the corporate side, the "building and lighting" category has encompassed over one third of the total direct actions[54] throughout the three reporting years. Further, on community-wide efforts, policy development actions such as update of building codes for emission reductions have been at the forefront of the "supportive actions"[55] taken by municipalities. Table C-10 below presents some of the types of actions in each of these major categories for corporate and community-wide efforts.

[50] http://www.cscd.gov.bc.ca/lgd/greencommunities/climate_action_charter.htm.

[51] http://www2.news.gov.bc.ca/news_releases_2013-2017/2015CSCD0020-000548.htm

[52] Local government corporate actions refer to efforts by local governments to reduce their own emissions. Overall, through the purchase of offsets and by undertaking measurable emission reduction projects, in 2013 BC local governments reduced their reported corporate greenhouse gas emissions by over 127,290 tonnes. Community-wide actions refer to the efforts that require the support of the greater community.

[53] http://www.cscd.gov.bc.ca/lgd/library/CARIP_2013_Summary_Report.pdf

[54] Direct actions are those that can be directly implemented and the impacts directly measured (e.g. installation of an energy efficient heating system).

[55] Supportive actions provide the framework to support implementation of direct action (e.g. development of policies, education programs, feasibility exploration). For clarity, the designation is not FEI's assessment of whether or not these initiatives are helpful or detrimental to its business.

Table C-10: Examples of GHG Reduction Direct and Supportive Actions Reported in Corporate and Community-Wide Spheres

	Community-Wide	Corporate
Direct Actions	Use of sustainability checklists for new buildings, Grants for improved residential energy efficiency, District energy and energy exchange systems, Geothermal, …	Solar heating for municipally owned buildings, building retrofits to improve heating efficiency, , …
Supportive Actions	Revised Official Community Plans (OCPs) to include GHG reduction targets, policies and actions, Development of Climate Action Plans, Community Energy and Emissions Plans, Development of policies related to buildings, transportation and waste (e.g. green building strategies), …	corporate climate action plans, corporate building policies, corporate fleet and energy use policies, …

The trends seen over the past number of years have solidified. Municipalities are making significant changes to their operations, policy, codes and regulations, which are having a direct negative impact on natural gas throughput. For instance:

- As part of the City of Vancouver's "Greenest City 2020 Action Plan", it is required that all new larger buildings – specifically, buildings classified in the building Bylaw as Part 3 and Part 9 non-residential buildings – be designed to strict energy standards. Energy reduction targets for new buildings are 20 percent below 2007 levels by 2020, and "carbon neutral" by 2030. The City also introduced Canada's first energy code/bylaw for existing larger buildings classified as Part 3 and Part 9 non-residential[56]. The 2020 energy reduction target for existing larger buildings is to reduce greenhouse gas emissions to 20 percent below 2007 levels[57].
- Under the City of Vancouver's "Green Home Program", new one and two-family homes are required to include a number of sustainable features that are focused on energy savings up to 33 percent by the year 2020. It is projected that the Vancouver Green Homes Program will be 14 percent more effective in reducing GHGs in new dwellings than what has recently been introduced in the BC Building Code. For instance, the recent amendments to Vancouver's by-law mandates that for boiler or furnace upgrades of over $5,000, the annual fuel utilization efficiency (AFUE) shall be equal to or more than 90 percent. The AFUE of 90 percent requires a condensing system. Generally speaking, with old homes it is expensive to convert the existing venting system to accommodate the venting system that is required for a condensing unit, which can lead to a migration of existing customers from natural gas condensing boiler/furnaces to electric ones.
- The recent amendment to the City of Richmond bylaws (amendment bylaw 9147) requires that new townhouses be designed (a) to score 82 or higher on the EnerGuide

[56] Vancouver is the only municipality in BC with its own building by-law. On April, 2014, the City Council enacted the 2012 BC Building Code with additional requirements and revisions specific to Vancouver.
[57] http://vancouver.ca/home-property-development/large-building-energy-requirements-forms-checklists.aspx.

Rating System (this is higher than the EnerGuide score of 77 that is currently required by the BC Building Code) and (b) be solar hot water-ready. Alternatively, new townhouses will be exempt from the above if they connect to a district energy utility or install industry proven renewable energy systems (such as geo-exchange, solar water heating, photovoltaic energy) which provide the majority (at least 51 percent) of heating, cooling and/or electrical energy load requirements[58].

- In 2012, Surrey City Council approved the District Energy System By-law which includes the requirement for all City Centre developments of a certain size to be fully compatible for district energy connection. Most recently, Council approved the Policy on Utility Rate Setting and Regulation which sets out the principles and methodology by which customer rates will be established and regulated by Council. The City's new City Hall and City Centre Library are already serviced by a new geo-exchange system. In addition, the City's district energy utility, Surrey City Energy, is preparing to begin construction of new thermal energy plants and associated distribution piping in order to provide thermal energy for the various developments currently planned and under construction in the City Centre.

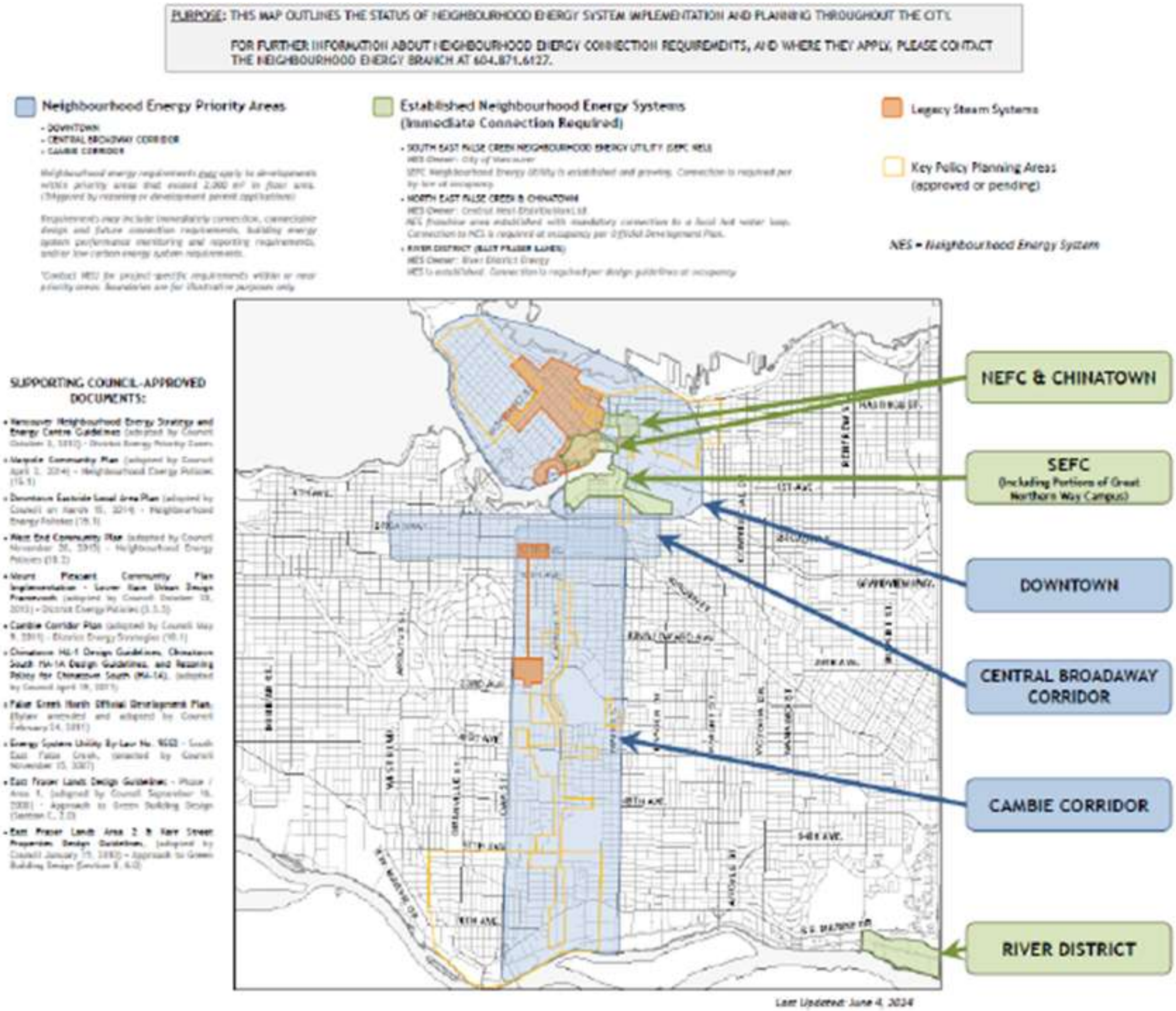
Similar programs can be found in most of the municipalities that have signed the Climate Action Charter. These actions by local governments promote moving away from natural gas (as the business as usual energy source) to other energy sources. They also encourage conservation and efficiency, which negatively impacts demand for natural gas (other things being equal).

The City of Vancouver's recent steps to endorse and promote the Creative Energy neighbourhood energy system in Northeast False Creek (NEFC) and Chinatown with an exclusive franchise for all space and water heating, backed by a mandatory connection bylaw, demonstrates an even greater willingness on the part of local governments to dictate energy choices in relation to non-municipal utilities. The mandatory connection obligation for developers in the proposed Creative Energy franchise area and exclusivity over space and water heating for Creative Energy prevents FEI from competing for this future load in the proposed franchise area.

Moreover, the City of Vancouver has indicated that the Creative Energy application is only a small part of a broader Vancouver Neighbourhood Energy Strategy. The Strategy includes conversion of the "Downtown Steam System", for "South Downtown" and for "other Expansion Areas" which includes the "West End" and "Downtown Eastside", "Cambie and Broadway Corridors". The following map prepared by the City depicts the breadth of the potentially affected areas:

[58] http://www.richmond.ca/__shared/assets/_2_OCPAmendment_EnergyEfficiency39053.pdf.

Figure C-38: Vancouver Neighbourhood Energy Strategy



FEI estimates that the Vancouver Neighbourhood Energy Strategy which includes NEFC and Chinatown, and other areas of Downtown, Central Broadway and Cambie Corridors currently represents an annual natural gas load of 10.5 PJ, which is approximately 5% of FEI's total annual load.

The framework being used with Creative Energy is applicable to new and significantly renovated buildings only, so FEI is not suggesting that the full 10.5 PJ would be immediately lost. However, at the same time, the 10.5 PJ does not include any potential for load growth in these areas. FEI does not have growth forecasts for these specific areas, or a forecast of the rate of redevelopment, so it is difficult to quantify the implications of the roll out of the Vancouver Neighbourhood Energy Strategy under a framework equivalent to that being proposed by the

COV and Creative Energy in NEFC. However, to provide a rough frame of reference, the delivery rate impact, other things being equal, associated with foregone load of 10.5 PJ would be a loss of revenue of approximately $32 million which equates to an increase of approximately 4.5% on natural gas delivery rates for the remaining FEI customers.[59]

(iii) ACTIVISM:

In recent years, environmentalists and anti-pipeline activists have increased pressure on companies involved in BC's pipeline and LNG projects. These movements seek to influence public policy and the actions of government bodies, and can impede infrastructure projects. The focus to date has been on oil and LNG infrastructure; however, activism of this nature poses an increasing risk for FEI, primarily because FEI is entering a phase of significant infrastructure development and renewal.

9.3 *CARBON TAX*

The carbon tax is an example of legislative or political action that has had direct implications for the price competitiveness of natural gas as an energy source in BC. The essential features of BC's carbon tax have remained consistent since the 2012 proceeding.

The following objectives were stated by the BC government for implementation of carbon tax[60]:

- to encourage individuals, businesses, industry and others to use less fossil fuel and reduce their greenhouse gas emissions;
- to send a consistent price signal;
- to ensure those who produce emissions pay for them; and
- to make clean energy alternatives more attractive.

As shown in Table C-11, British Columbia and Quebec are the only two provinces in Canada that have implemented carbon tax policies on fossil fuels[61]; however, British Columbia has a significantly higher carbon tax rate than Quebec. The BC carbon tax tripled from $0.50 per GJ in 2008 to $1.49/GJ in 2012, where it has remained.

[59] Based on approved FEI January 1, 2015 delivery rates, consumption as depicted in Figure 38 above, and FEI's approved total non-bypass delivery margin for 2015.
[60] http://www.fin.gov.bc.ca/tbs/tp/climate/carbon_tax.htm.
[61] Quebec also has a cap and trade program and Ontario introduced its own cap and trade program in 2015.

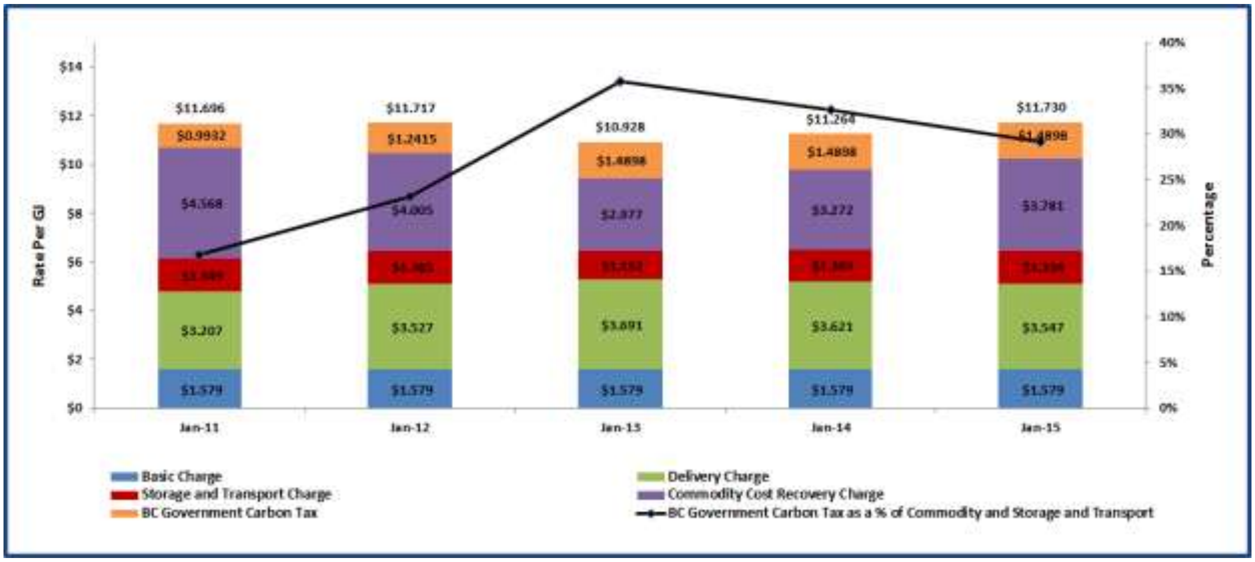
Table C-11: Provincial Carbon Tax Rate

Province	Start Date	Carbon Tax Rate
British Columbia	2008	\$10 per metric ton of CO_2e emissions in 2008, increasing \$5 annually to \$30 in 2012
Quebec	2007	\$3.50 per metric ton of CO_2e emissions

Source: National Renewable Energy Laboratory

The carbon tax represents a competitive challenge for FEI as it is a discrete tax applicable to natural gas and other fossil fuels, but not to electricity (despite the fact that some of the electricity that is consumed in BC is generated by fossil fuels in neighboring jurisdictions). Figure C-39 provides a historical look at gas prices from January 2011 to January 2015 for FEI residential customers in the Lower Mainland, which breaks out the carbon tax component.

Figure C-39: FEI Mainland Annual Residential Bill History[62]



Although no further carbon tax changes have been announced since the current carbon tax rate took effect in mid-2012, the potential for carbon tax increases and the level of future tax remain unknown at this time. The BC government has stated that, as other jurisdictions, especially within North America, introduce similar carbon taxes or carbon pricing, it may again review and consider changes to the carbon tax. In the meantime, the competitive impacts of the carbon tax persist.

[62] The analysis assumes a use rate of 90 GJs and includes all applicable rate riders. Prior to January 2015, rates are for the Lower Mainland service area only.

9.4 *ABORIGINAL RIGHTS AND TITLE*

FEI faces an elevated level of business risk related to relationships with First Nations in British Columbia relative to what existed at the time of the GCOC Stage 1 proceeding.

9.4.1 First Nations in British Columbia

Since FEI's activities span large parts of British Columbia, the Company comes in contact with a large number of Aboriginal groups in British Columbia.

Aboriginal and treaty rights are expressly recognized and affirmed by section 35 of the Constitution Act, 1982. This poses risk to all utilities in Canada. However, two main factors differentiate BC from elsewhere:

First, there is a larger number of First Nations in BC compared to the rest of Canada. British Columbia recognizes 285 different First Nations, Bands and Tribal Councils, which is over one-third of all Aboriginal groups recognized in Canada.

Second, most First Nations in BC are not signatories or adherents to a treaty (historic or modern) and most land in British Columbia is not covered by a treaty, unlike in most other provinces. Treaties assist in delineating rights of the signatory First Nations. As a result, many First Nations in British Columbia hold outstanding claims to Aboriginal title and rights. In addition, there can be competing claims from different First Nations over the same piece of land, necessitating that utilities deal with multiple First Nations in respect of specific assets.

In contrast, all of the land in Ontario and Alberta is covered by treaties, as well as most of the land in Quebec. Each of those provinces recognizes far fewer aboriginal groups, most of which are signatories to treaties.

The area of Aboriginal law is evolving and has potential implications for anyone proposing activities that may impact asserted Aboriginal rights or title, including FEI. Developments in case law have had, and may in the future have, a bearing on FEI's business by influencing government policy and processes of permitting authorities.

The Crown has a constitutional duty to consult and, if appropriate, to accommodate unproven Aboriginal rights and title that are asserted by Aboriginal groups. In the majority of cases, the procedural aspects – that is, the actual on-the-ground work of information sharing, learning about the potential impacts and the planning for mitigation - is delegated to the project proponent. However, the duty rests ultimately with the Crown, and FEI is dependent on the Crown's level of commitment to fulfil its duty. The project proponent (i.e. FEI) is affected by the pace and nature of any dealings between the Crown and the First Nation, and any court decision that halts a project for lack of adequate consultation.

Aboriginal law issues are not new to FEI. FEI conducts its business in a manner influenced by, and in accordance with Aboriginal law. However, the recent SCC Decision in *Tsilhqot'in Nation* *v. British Columbia*, 2014 SCC 44 increases FEI's business risk. It has done so by creating some uncertainty through several passages.

The *Tsilhqot'in* decision of the SCC represents the first time that a Canadian court has determined that Aboriginal title exists in respect of a particular tract of land. This has particular relevance in British Columbia where most land is subject to title claims by Aboriginal groups.

Where Aboriginal title has been established, the Crown must not only comply with its constitutional consultation obligation but also ensure that the proposed government action is consistent with Aboriginal title. Governments can only infringe proven Aboriginal title with consent of the title holder or, by meeting the established test for "justification". Prior to the establishment of title, the obligation on the Crown remains to consult and potentially accommodate Aboriginal groups asserting title. However, the SCC created some uncertainty by also stating (at para. 92) "if the Crown begins a project without consent prior to Aboriginal title being established, it may be required to cancel the project upon establishment of the title if continuation of the project would be unjustifiably infringing". These comments from the SCC have been interpreted broadly by First Nations as applying to facilities and projects that are already constructed and in place on lands subject to a declaration of Aboriginal title. The intent of these passages will likely be the subject of future litigation and interpretation.

The uncertainty described above, together with differing views on the scope of adequate consultation and accommodation, creates operational and regulatory complexity in British Columbia and a risk of litigation that is greater than other areas in Canada, and greater than it was in 2012.

10. REGULATORY RISK

The degree to which FEI, as a regulated public utility, is dependent on the Commission for timely and fair approvals to earn its return on and of capital results in what FEI refers to in this section as regulatory risk. Although PBR has introduced additional risk in some respects, the broader regulatory constructs that supported FEI's characterization of regulatory risk in 2012 remain in place. FEI has thus assessed its overall regulatory risk as being similar to what it was in 2012 with the potential to be higher over the term of the PBR.

10.1 *UNCERTAINTY AND LAG IN REGULATORY APPROVAL*

As a regulated public utility, FEI can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the Commission. The Commission sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The Commission, as a statutory entity, acts pursuant to its power under the *Act* but within that framework has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return on and of capital, or that necessary investments are not approved.

10.1.1 Regulatory Uncertainty

Regulatory uncertainty can be defined in different ways[63]. However for the sake of conciseness and for the purpose of this Application, FEI only considers the following three types of uncertainties:

- Uncertainty raised due to the unpredictability of future decisions of the current regulator (and its successors) which may be exacerbated by regulatory inconsistency;
- Uncertainty caused by vague decisions that are open to interpretation by the regulator (and its successors); and
- Uncertainty regarding the future implications of the regulator's decisions.

The determinations regarding cost of capital have a direct and significant impact on FEI's ability to earn a return on its invested capital that meets the Fair Return Standard. In the GCOC Stage 1 Decision the Commission acknowledged that the "*BC regulatory framework has a significant*

[63] For a comprehensive review of the definitions and taxonomy of regulatory risk please refer to the paper by Bastian Schwark titled "Influence of regulatory uncertainty on capacity investments – Are investments in new technologies a risk mitigation measure?", Retrieved from: http://infoscience.epfl.ch/record/153004/files/15d_schwark_paper.pdf.

influence on FEI's business and that individual decisions can have significant implications for FEI.[64]"

The Commission's decision in FEI's PBR Plan (PBR Decision) exemplifies how an individual Commission decision can have implications for FEI's ability to earn its fair return. Compared to cost of service regulation, performance-based rate-setting is subject to some additional risk associated with managing the controllable costs over a longer time horizon to a formulaic amount. This is particularly the case when the determined productivity improvement factor of the formula is higher than inflation and the expected industry productivity levels and therefore represents a risk to the balance between service quality, operating costs and capital costs under the PBR plan. In addition to this general risk inherent in all PBR plans, there are other specific aspects of the PBR Decision that have the potential to elevate regulatory risk for FEI during the PBR term:

- Reduction of FEI's growth factors by 50 percent: A major shift from previous PBR decisions in BC relates to the 50 percent reduction of growth factors in the PBR formulas. Considering that this is a new approach to PBR design in BC, the effect of this change may only be known after the PBR term[65]. This is particularly important for the PBR formula related to capital expenditures for service line additions, where the relationship between service line additions and spending is relatively linear and therefore the growth factor reduction may be considered a form of cost disallowance of prudently incurred costs.
- Potential disallowance of prudently incurred costs for exogenous events: The determination of the materiality threshold for exogenous events is another example of inconsistency between the PBR Decision and FEI's extensive history with PBR design. As explained in responses to information requests and discussed during the oral hearing, a materiality limit gives rise to the potential for denial of prudently incurred costs and increases the underlying risk to the Company.
- Backward-looking vs. forward-looking rate-setting elements of the PBR formula: Despite acknowledging some of FEI's reasoning for forecasting the formula drivers, the Commission determined that the inflation and growth factors of the PBR formula should be set based on backward looking historical data. This is analogous to cost of service regulation using a historical test year rather than a future test year. Forward test years have been a fundamental element of BC's regulatory framework and PBR formulas have always been determined based on forecast data. The Commission's decision to distance from this principle introduces some additional regulatory uncertainty.

In addition, as part of the PBR Decision, the Commission directed FEI to file a formal proposal for the addition of FEVI's and FEW's O&M and capital requirements to FEI's base O&M and capital to reflect the amalgamated FEI entity. FEI filed its proposal to include FEVI and FEW

[64] GCOC Stage 1 Decision, p.40.
[65] For 2015, the growth capital is projected to be above the formula by more than $9 million.

within the PBR plan on November 14, 2014. Commission Order G-106-15 set FEVI's sustainment capital based on a five year average of FEVI's actual sustainment capital expenditures and reduced FEVI's previously approved 2014 sustainment capital by $6.3 million which resulted in a similar reduction to Base Capital Expenditures for 2015 and each of the remaining years in the PBR term. This is an example of how one element of PBR design can create uncertainty over the term of the PBR.

10.1.2 Regulatory Lag

Regulatory lag is defined as a delay between incurring a cost and the implementation of the rates that recover these costs. The growing complexity of FEI's operating environment can also lead to delays (regulatory lag) in system investments, or the delivery of service offerings. Regulatory lag can present a risk for FEI's return on and of capital.

One aspect of regulatory lag is the time between application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and when the final order related to that application is issued. While the need to conduct regulatory reviews of utility operations is an integral part of being a public utility, the resulting delay does create risk for the utility. Risk arises in part because it is necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or that the projects contemplated and required to be undertaken will ultimately be approved.

Certain regulatory processes for FEI applications have recently been lengthy, resulting in extensive periods during which the utility is operating on interim rates. For instance, FEI's 2014 PBR application was filed in June 2013 while the PBR Decision was released in mid-September 2014. Despite this, overall regulatory lag is viewed as unchanged since 2012.

10.2 *DEFERRAL ACCOUNTS*

Deferral accounts can help to reduce the rate impact and rate volatility for customers. The Commission determined in the 2009 Cost of Capital Decision that "…the effect of deferral accounts in reducing the risk of [FEI] as reducing the short-term, and not the long-term, business risk of [FEI]...".[66]

The majority of FEI's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the Company. In the recent PBR Decision, the Commission directed FEI to discontinue the use of a number of deferral accounts;[67] however, the discontinuance did not, in and of itself, materially change FEI's short-term risk profile since the Commission also directed FEI to true-up those costs each year

[66] 2009 Cost of Capital Decision, p. 19.
[67] Tax variance deferral account, the property tax variance deferral account, the insurance expense variance deferral account and the interest expense variance deferral account.

through a flow-through mechanism[68] for the term of the PBR Plan. The rest of FEI's key deferral accounts remained unchanged. The discontinuation of long-standing deferral accounts in favour of a PBR specific mechanism has increased regulatory risk over the longer term because it is unknown how these costs will be addressed once FEI emerges from its PBR Plan. Table C-12 summarizes the general categories of FEI's deferral accounts.

Table C-12: Deferral Accounts

Deferral Account Category	General Purpose & Description
Margin Related	• Decreasing the volatility in rates caused by such factors as fluctuations in commodity prices and the significant impacts of weather on use rates • Deferring the cost of gas and delivery margin impacts arising from un-forecast variations in these types of factors and recovering them from/refunding them to customers over a longer period of time to reduce rate volatility Examples: Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (MCRA) and Revenue Stabilization Adjustment Mechanism (RSAM)
Energy Policy	• Capturing costs associated with energy policies that focus on energy efficiency, conservation and the environment • Deferring and amortizing these costs matches the costs of the programs with a reasonable period of time over which the benefits are expected to be realized by customers Examples: Energy Efficiency and Conservation (EEC), NGT Incentives
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers Examples: Flow-through deferral account, Pension and OPEB Variances, BCUC Levies Variance
Costs of BCUC Applications	• Captures costs required to support regulatory applications, such as intervener and participant funding costs, Commission costs, costs for expert witnesses and consultants, costs related to independent validation of study results, legal fees, required public notifications, and miscellaneous other costs Example: 2014–2019 PBR Application Costs deferral account
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature Examples: Whistler Pipeline and Conversion Costs, BCOneCall Project, Gas Asset Records Project

[68] The flow-through deferral account also includes items such as customer variances for residential and commercial customers as well as the industrial margin variance.

10.3 *ADMINISTRATIVE PENALTIES*

On May 31, 2012, Bill 30 – *Energy and Mines Statutes Amendment Act, 2012* – received Royal Assent. Bill 30 amends several statutes, including the *Clean Energy Act*, *Oil and Gas Activities Act* and *the Act*. In the GCOC proceeding, FEI had identified the new administrative penalties as a change in its regulatory environment since 2009. There has been no change in status of administrative penalty framework since its implementation. FEI also recognizes that administrative penalties can only be issued if FEI is found to have breached legislation or a Commission order. This discussion is included for the sake of completeness only, and FEI has not assessed any change in business risk associated with administrative penalties.

Appendix D

DRAFT ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for a Common Equity Component and Return on Equity Effective January 1, 2016

BEFORE:

(Date)

WHEREAS:

A. On May 10, 2013, the British Columbia Utilities Commission (Commission) issued its Decision Order G-75-13 for Stage 1 of the Generic Cost of Capital proceeding (the Stage 1 Decision);

B. The Stage 1 Decision directed FortisBC Energy Inc. (FEI) to file an application for review of the common equity component and Return on Equity (ROE) approved in the Stage 1 Decision, by no later than November 30, 2015;

C. On October 2, 2015, pursuant to the Stage 1 Decision, FEI filed for approval of a capital structure consisting of 40 percent equity and 60 percent debt and an ROE of 9.5 percent.

D. The Commission has considered the evidence and the submission of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. FEI's common equity component is 40 percent, effective January 1, 2016.

2. FEI's ROE for ratemaking purposes is 9.5 percent, effective January 1, 2016.

3. FEI remains the benchmark utility for the purpose of determining the cost of capital for other utilities that presently use FEI as the benchmark utility, and the ROE approved in Paragraph 2 of this Order will serve as the benchmark for that purpose.

4. Within 30 days of the date of this Order, FEI is to file:

   a. A document setting out how and when it will implement the change to its capital structure;

   b. Amended rate schedules in accordance with paragraphs 1 and 2 of this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER