APPENDIX F

THE REGULATORY FRAMEWORK AND UTILITY RISK

Q. WHAT RISKS DO INVESTORS FACE IN INVESTING IN UTILITIES?

A. Investors are interested in the rate of return on the *market value* of their investment. This investment can be represented by the standard discounted cash flow model,

$$P_O = \frac{ROE * BVPS * (1-b)}{K-g}$$

where P_0 is the stock price, *ROE* the return on *book equity*, *BVPS* the book value per share, *b* the retention rate (how much of the firm's earnings are ploughed back in investment) and *K* and *g* are the investor's required rate of return and growth expectation respectively.[1]

Of the different sources of risk, we normally focus on the firm's *business* risk**,** its *financial* risk, and its *investment* risk**.** For regulated utilities we also add a fourth dimension, namely its *regulatory* risk**.** In terms of the above equation the firm's accounting return on equity **(ROE)** captures the business, financial and regulatory risk, which together we term income risk, whereas all the other factors are reflected in investment risk, which is the way in which investors react to the income risk and other macroeconomic variables. The regulator primarily affects income risk, whereas investment risk is determined in the capital market and reflects, for example the impact of changing interest rates.

Business risk is the risk that originates from the firm's underlying "real" operations. These risks are the typical risks stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method of production used by the firm and the uncertainty in the firm's cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials.

[1] This equation is in every introductory finance textbook as *d/(K-g)* where *d* is the dividend or *ROE*BVPS*(1-b)*.

Business risk, to a greater or lesser degree, is borne by **all** the investors in the firm. In terms of the firm's income statement, business risk is the risk involved in the firm's earnings before interest and taxes (EBIT). It is the EBIT, which is available to pay the claims that arise from all the invested capital of the firm, that is, the preferred and common equity, the long-term debt, and any short-term debt such as debt currently due, bank debt and commercial paper.

If the firm has no debt or preferred shares, the common stockholders "own" the EBIT, after payment of corporate taxes, which is the firm's net income. This amount divided by the funds committed by the equity holders (shareholder's equity) is defined to be the firm's return on invested capital or ROI, and reflects the firm's operating performance, independent of financing effects. For 100% equity financed firms, this ROI is also their return on equity (ROE) since the entire capital investment has been provided by the equity holders. The uncertainty attached to the ROI therefore reflects all the risks prior to the effects of the firm's financing and is commonly used to measure the business risk of the firm.

As the firm reduces the amount of equity financing and replaces it with debt or preferred shares, two effects are at work: first the earnings to the common stockholder are reduced as interest and preferred dividends are deducted from EBIT and, second the reduced earnings are spread over a smaller investment. The result of these two effects is called financial leverage. The basic equation is:

$$ROE = ROI + (ROI - R_d(1-T))\, D/S$$

where D, and S are the amounts of debt, and equity respectively in terms of ***book*** values. If the firm has no debt financing (D/S =0) and the accounting return to the common shareholders (ROE) is the same as the return on investment (ROI). In this case the equity holders are only exposed to business risk. As the debt equity ratio increases, the spread between what the firm earns, and its borrowing costs is magnified. This magnification is called financial leverage and measures the **financial risk** of the firm. The simplest way to measure this financial risk is through the debt equity ratio, since this measures how many dollars of debt have been raised for every dollar of shareholder's equity.

The common shareholders in valuing the firm are concerned about the total "income" risk they must bear, which is the variability in the accounting ROE. This reflects both the underlying business risk as well as the added financial risk. If the firm operates in a highly risky business, the normal advice is to primarily finance with equity, otherwise the resulting increase in financial risk might force the firm into serious financial problems. Conversely, if there is very little business risk, as is the case with regulated utilities, the firm can afford to carry large amounts of debt financing, since there is very little risk to magnify in the first place.

Business risk is then equivalent to variability in EBIT or the *ROI*, both of which reflect the variability in the firm's operating costs and revenues. To analyse this, we normally look at how easy it is to forecast operating costs and how stable revenues are.

These comments mean that any regulatory authority has a variety of tools to manage the regulated firm's income risk. The ***first*** is it can manage the different components of business risk. The basic way that a regulatory authority can do this is by establishing deferral accounts. The essence of deferral accounts is simply to capture major forecasting errors. Instead of having the utility's shareholders "eat" any cost over runs or demand shortfalls in terms of a lower earned or actual ROE, the regulator can simply pass the extra costs to a balance sheet deferral account. The value of the deferral account is then charged to the ratepayers over some future time-period. In this way "ratepayers" always pay the full cost of service and stockholder risk is lowered.

A **second** tool is for the regulator to alter the amount of debt financing. If the regulator feels that the firm's business risk has increased (decreased) it can reduce (increase) the amount of debt financing so that the total risk to the common stockholder is the same. Both of Canada's national regulators, the National Energy Board (now the Canadian Energy Regulator) and the CRTC, have recognized this. When the CRTC opened Canada's telecommunications market to long distance competition it specifically increased the allowed common equity component of the Telcos to 55% to offset their increased business risk. More specifically, when the National Energy Board decided to implement a formula-based approach for the ROE in 1994 it reviewed all the capital structure ratios for the major oil and gas pipelines and set the oil pipelines at 45% common equity, Westcoast at 35%, and the remaining mainline gas transmission companies at

30%. In each case the different equity ratio adjusted for differences in perceived business risks so they could all get the NEB formula ROE.[2]

The **third** tool available for the regulator is to directly alter the allowed ROE, so that the shareholder only earns an ROE commensurate with the risks they bear. The CRTC, for example, historically allowed Northwestel 0.75% more than the other Telcos primarily due to the "ruggedness" of its operating region. The BC Utilities Commission (BCUC) has allowed Pacific Northern Gas a premium over its low-risk utility (Fortis BC Gas) and the Alberta Utilities Commission (AUC) also allows ROE premiums over its generic allowed ROE as well as differential common equity ratios.

Q. WHICH TOOLS DO YOU ADVOCATE USING?

A. It makes sense that any significant forecasting risks that are largely beyond the control of the firm should be managed though the use of deferral accounts. The reason for this is simply that they do not affect the efficiency of the utility and there are diversification gains by spreading the variability over many customers. As a result, deferral accounts are a "win-win" solution as they reduce the operating risk faced by the company, thereby allowing a higher debt ratio and consequently they lower overall cost of capital thereby benefiting customers. For this reason, I have long argued that companies should have deferral accounts for the cost of short-term debt, for example, since no-one can predict short term interest rates and otherwise there may be a tendency to overestimate them.[3]

With a choice between capital structure versus ROE adjustments; my preference is to adjust for business risk in the capital structure for two main reasons. First, the market seems to consider any changes in the allowed capital structure to be a more permanent change, while it expects the ROE to change with capital market conditions. Since business risk is the primary determinant of capital structure, it is to be expected that a regulator will change an allowed capital structure relatively infrequently in response to significant changes in business risk. Second, allowing firms

[2] Westcoast was allowed a higher common equity ratio because of the greater share of non-mainline assets in its rate base. The mainline tolls were based on a 30% deemed common equity.

[3] Moody's specifically refers to the ability of a utility to earn its allowed ROE as a factor in determining the utility's bond rating.

to choose their capital structure and then adjusting the ROE to a fair return runs the risk that although the equity holders are getting a fair rate of return the overall utility income and thus rates are too high and unfair. An extreme example here would be a regulated firm that “chooses” 100% equity financing. The regulator might then give a fair ROE, but rates are still unfair and unreasonable since the company is forgoing the advantages of using debt financing.

One corollary to the decision of many regulators such as the CER, the BCUC and AUC to adjust capital structures in response to business risk differences is that the risk faced by shareholders in Canadian utilities is very similar. This is the very essence of why the AUC and BCUC, for example, have generic hearings on the ROE: to a great extent they have reduced differences in business risk by allowing the use of deferral accounts and altering equity ratios.

Q. WHY IS THE COMMON EQUITY RATIO IMPORTANT?

A. The firm’s capital structure has a direct impact on the overall cost of capital as conventionally defined in finance. This calculation uses market value weights and costs because some of these costs are affected by the corporate tax rate. It is often called the WACC or ATWACC for this reason. Note that this is not the same thing as the utility weighted average cost of capital that uses book value weights and normally does not directly consider these tax effects. In the following discussion wherever I use the phrase cost of capital I am referring to the conventional, that is, non-utility definition

This topic has been the subject of enormous academic inquiry over the last sixty years and has directly generated two Nobel Prize winners in Professors Franco Modigliani and Merton Miller. However, for all the sophistication of the academic models, the most important issue is that certain types of financial instruments have a tax-preferred status. In Canada this status is accorded debt instruments, since interest payments are tax deductible to the firm, whereas equity dividends are not. As a result, there is a built-in tax advantage to any corporation using debt financing. This tax advantage goes to the ***shareholders*** of unregulated firms and to the ***customers*** of regulated firms since the use of debt reduces the firm’s revenue requirement. As will be discussed later, this asymmetry in benefits for the regulated firm is a motivating factor behind regulated companies continually striving to increase their common equity ratios.

The primary fact to remember is that equity costs are paid out of **after-tax** income, whereas debt costs are tax deductible. Hence, for example, if debt costs are 4.0% and equity costs are 8.0%, then at a 33% tax rate (for simplicity), the **pre-tax costs** are 12.0% for the equity (.08/(1-.33)) compared to 4.0% for the debt. Conversely the after-tax costs are 2.67% and 8.0%; either way the costs of debt versus equity must be compared on the same tax basis. It is these "same tax" cost comparisons, whether before or after tax, that competitive firms make in deciding their financing. This implies that there is an incentive for competitive firms to finance with debt: as they replace expensive equity with "cheap" debt, their cost of capital goes down. Hence, for the same fixed amount of operating income, the shareholder benefits from the tax advantage of debt financing for competitive firms.

Q. HOW DO WE KNOW THERE IS A TAX ADVANTAGE TO THE USE OF DEBT?

A. The most obvious example is to look at the pricing of preferred share dividends versus government of Canada debt securities. Preferred stock is a form of contract like a bond and in Canada they have been structured to mimic bonds for investors interested in receiving dividend versus interest income due to tax preferences. In their June 2004 issue of their Preferred Share Quarterly Statistics BMO-Nesbitt Burns provided the following yields.

	June 2004
Retractable Preferreds (%)	
Dividend yield	4.01
Mid Canada yield	4.09
After tax spread (corp)	1.77
After tax spread (indiv)	0.63
Straight Preferreds (%)	
Dividend yield	5.48
Long Canada yield	5.34
After tax spread (corp)	2.54
After tax spread (indiv)	0.98
Floating Rate Preferreds (%)	
Dividend yield	3.42
BA (3 month)	2.12
After-tax spread (corp)	2.25
After-tax spread (indiv)	1.22

The retractable preferreds are compared to mid Canada bonds, since the retraction feature shortens their maturity as compared to a long bond. The traditional straight preferreds are compared to long Canada bonds, while the floating rate preferreds are compared to 90-day Banker's acceptances (BAs), since their dividends are usually reset quarterly like a roll over strategy in the money market. In this way the preferred shares are compared to different classes of bonds that they are designed to mimic.

The important point about the comparison is that what we observe in the capital market is a pre-tax yield. This is determined by both risk and taxes. Take the straight preferreds, for example, in June 2004 the long Canada bond had a yield of 5.34%, while straight preferreds had a yield of 5.48%. The preferreds would be regarded as riskier than the long Canada bond, since the corporate issuer can default but the "pre-tax" yield difference between them was only 0.14%. However, once we consider that inter corporate dividends are tax free in Canada, the after-tax yield difference increases to 2.54%. In contrast for a private investor in the top tax bracket the after-tax yield difference is smaller at 0.98%.

The reason that the after-tax spreads are larger than what we observe in the capital market is that dividend income gets more favourable tax treatment than interest income at the investor level.[4] The correct comparison is the after tax yield difference, which BMO-Nesbitt-Burns gives as 2.54% in favour of the preferred shares for corporates and 0.98% for individuals, which is the correct result: that on an after tax basis the riskier preferreds give a higher yield. Also note that for the short-term bonds, the pre-tax mid Canada yield at 4.09% was higher than the yield on the retractable preferreds. An ill-informed person might incorrectly state that the mid Canada bond was riskier than the retractable preferreds based on the second rule of finance: the risk-value of money. A better-informed person however would point to the after-tax spread of 0.63-1.77% and point out the third rule of finance: the tax value of money.

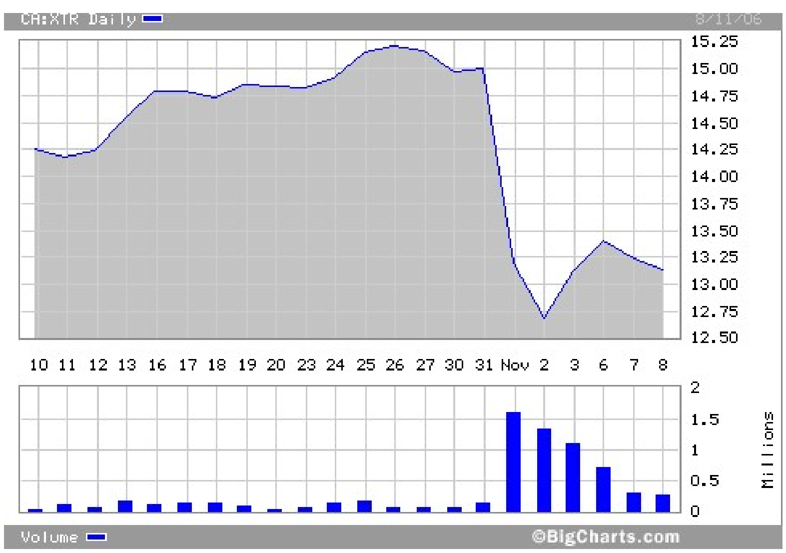
What the BMO data indicates is that taxes affect the yield we observe in the Canadian capital market. Consequently, a huge amount of corporate financing revolves around tax motivated

[4] This is because Canada, unlike the United States, operates an integrated tax system where the tax preference for dividend income at the investor level reflects the prior payment of corporate income taxes.

transactions. For example, the Government of Canada changing the tax status of income trusts is a vivid reminder of their importance. Income trusts invest in both the debt and equity of an operating company, where the debt is structured to remove the corporate income tax liability of the operating company. The trust is then non-taxable, since it is legally the same as a mutual fund, and flows the interest on the debt, the dividends on the equity, plus other non-cash charges like depreciation, through to the trust unit holders. The income trust structure, therefore, effectively removes the corporate income tax.

Income trusts were incredibly popular in Canada since the absence of the corporate income tax allowed more income to flow through to investors. Even though in 2006 the conservative government in Ottawa campaigned on ‘no changes to the tax treatment of income trusts,’ their hand was forced by the announcement of Bell Canada Enterprises that it was following the lead of Telus and converting to an income trust structure. There were also rumours that Encana and Suncor were planning $40 billion in income trust conversions of their oil and gas assets. The result was that on October 31, 2006, after the markets closed the Federal Minister of Finance, Mr. Jim Flaherty, announced that all new trusts would be subject to a 31.5% distribution tax to put them on the same tax status as corporations and that existing trusts would pay this tax in five year’s time.

The importance of the income tax changes can be understood from the following graph that tracks the price of the exchange traded income trust fund, XTR.



Before the Minister of Finance's decision, the income trust ETF was at $15 and the day after it had dropped to $13.25 and then on November 2 even further to $12.75 before rebounding slightly. Most analysts predicted that the tax changes would cause income trusts to drop in value by 20-25%, but the effect varies across different trusts depending on the proportion of Canadian to foreign income and the type of income, that is, how much is a return of capital and how much newly taxable income. Plus, the existing trusts would only be taxed after a four-year grace period, that is, in five year's time.

Regardless the carnage on Bay Street caused by the changing tax rules vividly demonstrates that the corporate income tax has a huge impact on the valuation of shares. Another way of saying this is that by removing the corporate income tax and financing with debt adds of the order of 15-20% to the market value of the firm. We can see this from the fact that the exchange traded fund would sell for $15 without the corporate tax and about $13 with the tax levied in ***five year's*** time. The impact of the time until the tax is levied means that the true value of removing the corporate income tax is much greater than these price changes indicate.

Q IF DEBT IS SO MUCH CHEAPER THAN EQUITY WHY DON'T FIRMS USE MORE?

A. They try to use as much debt as they can, but unlike income trusts the debt is held by third parties. The beauty of the income trust structure is that the debt and equity is held by the same party (the trust) so if a firm has trouble making an interest payment it negotiates with the same party that owns the equity. However, for regular corporations the debt is owned by banks and public institutions, like pension funds, insurance companies etc., that are not identical to its shareholders. As a result, there are limits to the amount that firms can borrow due to the increased costs of financial distress that are associated with higher fixed financial charges. In extreme cases, the higher fixed financial charges can force a firm to be reorganised, or taken over, when it could probably have otherwise survived had it been financed with less debt. As a result, it is a basic rule of corporate finance that the financial risk is **layered** on top of business risk: firms with high business risk are advised not to issue too much debt, otherwise their solvency could be jeopardised in the event of adverse market developments.

This basic discussion is relevant since publicly traded firms are constantly re-assessing their capital structures ("improving their balance sheets") considering changing market conditions and the changing risk of financial distress. It also explains why capital structures differ from one firm to another, since both the nature of their assets and expected cash flows are different. One firm with mainly hard tangible assets will use large amounts of debt, since these types of assets are easy to borrow against. Another firm that spends significant amounts on advertising will have relatively little debt, since it is harder to borrow against brand names and "goodwill." Yet another firm will use very little debt, since it is not in a tax paying position and cannot use the tax shields from debt financing. And finally, a firm may use very little debt simply because it believes that its equity is cheap because its stock price is so high. In each case, the firm will solve its own capital structure problem based on its own unique factors.

This discussion puts the utility capital structure in perspective since utilities have the lowest business risk of just about any sector in the Canadian economy. Consequently, they should have the highest debt ratios. There are several reasons for this:

> **First**, the costs and revenues from utility operations are very stable so that the underlying uncertainty in operating income is very low. As such financial leverage is as I will show essentially magnifying almost non-existent ROI/EBIT variability and zero times anything is still zero!
>
> **Second**, in the event of unanticipated risks, regulated utilities are the **only** group that can go back to their regulator and ask for "after the fact" rate relief. As effective monopolies their rates can be increased in the event of financial problems, while demand is typically insensitive to these rate increases. In contrast, if unregulated corporations face serious financial problems, they usually compound one another. This is because unregulated firms encounter difficulties raising capital and frequently suppliers and customers switch to alternates in the face of this uncertainty creating severe financial distress.
>
> **Third**, the major offset to the tax advantages of debt is the risk of bankruptcy. In liquidation there are significant external costs that go to neither the equity nor the debt holders. These costs include "knock down" asset sales, the loss of tax loss carry forwards, and the reorganisation costs paid to bankruptcy trustees, lawyers etc. This causes non-regulated firms to be wary of taking on too much debt, since value seeps out of the firm. In contrast, it is difficult to think of Energir's pipes being ripped up and sold for scrap in the near term.
>
> **Finally**, most private companies have an asset base that consists largely of intangible assets. For example, the major value of Nortel was its growth

opportunities; of Coca Cola its brand name; of Merck its R&D team. It is extremely difficult for non-regulated firms to borrow against these assets. Growth opportunities have a habit of being competed away; brand names can waste away, while R&D teams have a habit of moving to a competitor. Regulated utilities in contrast largely transmit un-branded services and derive most of their value from tangible assets. Unlike intangible assets, tangible assets are useful for collateral as, for example, in first mortgage bonds, and are easy to borrow against.

Consequently, intrinsically utilities have very low business risk; have reserve borrowing power by being able to return to the regulator, minuscule bankruptcy/distress costs and hard tangible assets that are easy to borrow against. In fact, utilities are almost unique in terms of their financing possibilities,[5] and are prime candidates for using large amounts of debt to utilise their very significant tax advantages.

Q ARE THE ABOVE IDEAS STANDARD IN FINANCE?

A. Yes. A popular finance textbook is Fundamentals of Corporate Finance, McGraw Hill Irwin (3^{rd} edition) by Brealey, Myers and Marcus). In chapter 15 the text discusses capital structure and notes the following:

- (Page 434) "Debt financing has one important advantage. The interest that the company pays is a tax-deductible expense, but equity income is subject to corporate tax."
- (Page 434 and 435) The interest tax shield is a valuable asset. Let's see how much it could be worth……………………If the tax shield is perpetual, we use the perpetuity formula to calculate its present value:

$$\textbf{PV tax shields} = \frac{annualtaxsheild}{r_{debt}} = T_c D$$

- (Page 435, 436) How interest tax shields contribute to the value of stockholder's equity….

Value of levered firm = value of all-equity firm + T_CD

- (Page 444) For example, high-tech growth companies, whose assets are risky and mainly intangible, normally use relatively little debt. Utilities or retailers can and do borrow heavily because their assets are tangible and relatively safe.

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5 When we analyse corporate financial decisions, we normally include a number of explanatory variables and then add a "dummy" variable for whether or not the industry is regulated, since the mere fact of regulation is frequently the most significant feature of a firm's operations.

These four comments are taken from the discussion of what is commonly referred to as the static trade-off model, where the tax advantages of debt financing are traded off against the costs of financial distress and loss of financial flexibility. They are referenced simply because there is little disagreement amongst academics that debt is valuable to the firm due to the tax shields it generates. This consensus has then been amply verified by the stock market's reaction to the changing status of income trusts. As the second point indicates if debt is rolled over, so that the interest and tax shields are expected to continue indefinitely, then the value of the tax shield is the amount of debt times the corporate income tax rate. At a 30% corporate tax rate this means that every dollar of debt adds 30 cents in value to the common shareholders. The third quote indicates that the value of the firm is increased by the present value of these tax shields. In fact, the equation referenced there is part of an approach called adjusted present value (APV), which focuses heavily on the tax advantages to debt, and which has been widely used to value financial engineering strategies involving leveraged buyouts etc that remove the corporate income tax. The final quotation specifically mentions utilities as companies that should borrow.

In 2006 Deutsche Bank published a study Corporate Capital Structure, January 2006 with a review of the basic principles for determining corporate use of debt and the results of their survey of chief financial officers with the following relevant results on page 42.

Figure 21: Factors in Determining Level of Debt

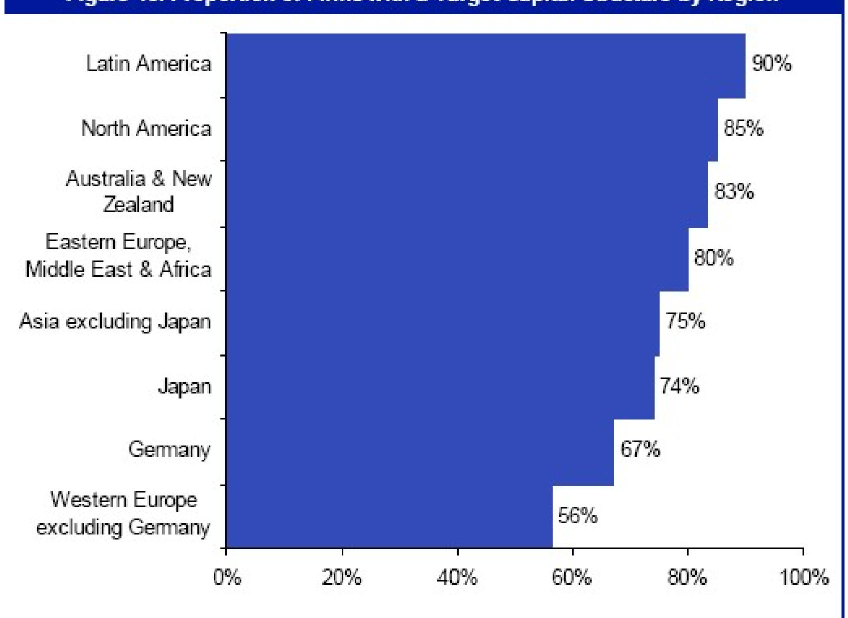
Factors	% 4 or 5	N
Credit rating	57%	252
Ability to continue making investments	52%	253
Tax shield	32%	256
Ability to maintain dividends	31%	254
The market's capacity for my debt	29%	248
Transaction costs on debt issues	25%	252
Other companies in industry	20%	250
Credit spread relative to fair spread	18%	246
Competitor actions when debt is high	18%	248
Ability to manage Earnings per Share	17%	246
Other companies in rating category	16%	246
Supplier attitudes	15%	255
Customer attitudes	13%	253
High debt => efficient management	8%	248
Shareholders maintaining control	7%	243
Investor taxes	6%	246
Debt signals high quality	6%	246
Creditors rights in home jurisdiction	5%	244
Signalling to competitors	5%	249
Employees attitude to high debt	4%	255
Debt improves employee bargaining	0%	247

Q3.2: "How important are the following factors in determining the appropriate level of debt for your company?" Scale is Not Important (0) to Very Important (5).

We see the importance of credit ratings (market access), ability to continue to make investments and maintain dividends (financial flexibility and fear of distress) and tax shields. This survey reinforces the basic “static trade-off” model that firms balance the tax advantages of debt against the restrictions it imposes on their activities and the fear of financial distress. As a result, they have an optimal or target capital structure.

On page 37 of their report Deutsche bank had the following table where fully 85% of North American firms reported that they had a target capital structure, second only to firms in South America. Why this is important is that this target capital structure represents the trade off the factors discussed above and reinforces the academic literature that has modelled this trade off.[6] Overall both the literature and the practise of corporate finance emphasises the existence of an optimal capital structure for the firm and that it is not a random choice. Further the view that there is “no magic” in leverage is incorrect. Obviously, if there were “no magic in leverage,” firms would not have a target capital structure in the first place. Further as I show in my ATWACC appendix the corollary of having an optimal capital structure is that there is a minimum ATWACC and deviating from this optimal level causes it to increase.

Figure 18: Proportion of Firms with a Target Capital Structure by Region



[6] Note that as discussed above, this does not mean that this target is constant.

Q. WHY ARE THE QUEBEC UTILITIES ASKING FOR A HIGHER COMMON EQUITY RATIO?

A. We have to remember that as tax paying entities they should act like a competitive firm and use debt to minimise taxes. However, whereas the gains to using debt flow to the shareholders in a regular corporation, in a regulated utility they are a cost of service. So automatically any reduction in income taxes due to the use of debt financing ***automatically*** reduces the revenue requirement and flows through to the ratepayers. Consequently, there is no value to the utility's shareholders for using debt to offset its disadvantages.

The Alberta EUB has noted the above (TransAlta EUB 2003-061, August 2003, page 103) where it stated:

> "The Board notes that since cost of capital recovery is provided for through its annual revenue requirements, a regulated utility, like Alta Link, would naturally wish to maintain low debt ratios. This allows the utility to minimize the financial risk imposed on equity investors, and to also maintain high debt ratings."

The use of debt financing is thus like any other efficiency gain in that the gains should be competed away and flow through to the customers.

One would hope that the managers of a utility are professionals, so that they operate the utility in a professional way to reduce costs. However, they have alternative incentives since under corporate law

> *"Every director and officer of a corporation in exercising his powers and discharging his duties shall:*
>
> *1) act honestly in good faith with a view to the best interests of the corporation; and*
>
> *2) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances."*

Further the governance guidelines of the TSX (Where Were the Directors, 1994, the Dey Report) indicate that

> *"We recognize the principal objective of the direction and management of a business is to enhance shareholder value, which includes balancing gain with risk in order to enhance the financial viability of the business."* (S 1.11)

What this means is that the directors have a fiduciary responsibility towards the company's shareholders. In this context the managers of a privately owned utility are acting like the managers of any other private corporation, which is to say in the best interests of their shareholders and not necessarily acting to reduce costs to ratepayers.

Q. ARE THERE SPECIAL PROBLEMS WHEN UTILITIES ARE OWNED BY OTHER COMPANIES?

A. Yes. As indicated above, if there is a tax advantage to using debt, then competitive firms will use debt. However, for ROE regulated utilities this tax advantage flows through to the consumer as a lower tax charge in the revenue requirement. As a result, there is no advantage to the utility using debt. However, for utilities owned by a utility holding company (UHC) the situation is worse, since the parent has an incentive to finance the utility with as much equity as possible, so that the tax advantages to debt are shifted to the parent. In this way it is the UHCs shareholders that get the tax advantages of financing with debt instead of the utility ratepayers. If the utility is not at its optimal capital structure, then it is leaving some of its debt capacity to be used by its parent.

This is often called the "double leverage" problem, where the utility assets support debt at both the utility level and then again at the parent level. Another word for this is *pyramiding* where the holding company may also have a parent borrowing on the strength of the holding company and then the operating company. In the run up to the Great Stock Market Crash of 1929 in the US this pyramiding of electric utility companies was believed to be a major factor in the crash since each layer in the pyramid was partly debt financed the true amount of equity was reduced leaving them vulnerable to a cascade and collapse. Columbia Gas and Electric had reported equity capital of $194 million, but when all the intra-corporate transactions were removed, it was reduced to $12.3 million.[7]

The experience in the US led to the passage of the Public Utility Holding Company Act of 1935 and direct supervision by the Securities and Exchange Commission (SEC) where the SEC:

[7] Public Utility Holding Company Act of 1935 - Wikipedia

- limited a UHC to ownership of a single electric utility
- prevented the over recovery of common expenses
- prohibited sales of goods and services between the UHC and its operating subsidiary

All of which led to a significant restructuring of the ownership of US electric utilities and a desire to see more common equity used in their financing to avoid the 1929 experience.

The PUHCA was largely repealed in 2005 while Congress was reducing the regulatory supervision of the thrift industry, which eventually led to the US financial crisis of 2008 as old habits resurfaced. In the same way the repeal of the PUHCA has led to significant Mergers and acquisitions activity in both the US and Canada. This concern led some rating agencies, such as Standard and Poors, to rate the debt of the operating subsidiary based on the credit rating of the parent. The principle here is that if the parent gets into trouble, it will "raid" the subsidiary unless it is "ring fenced" or insulated from the parent in some way.

S&P is very forthright in that the onus lies on the regulators. It states

> ***"the bar has been raised with respect to factoring in expectations that regulators would interfere with transactions that would impair credit quality. To achieve a rating differential for the subsidiary requires a higher standard of evidence that such intervention would be forthcoming."***

It is clear from this comment from S&P that the business risk of a utility is only one factor in the bond rating. Further the combination of weak US regulatory oversight and ownership of a utility within a diversified holding company with a weak bond rating dooms the utility to also have a weak bond rating ***regardless*** how strong its common equity ratio and how high its allowed ROE.

In response, S&P implemented a policy that the credit rating of a regulated telecom can not be higher than the credit rating of its parent. For non-telecom utilities S&P stated[8]

> ***"rarely view(s) the default risk of an unregulated subsidiary as being substantially different from the credit quality of the consolidated entity. Regulated subsidiaries can be treated as exceptions to this rule – if the specific regulators involved are expected to create barriers that insulate a subsidiary from its parent."***

[8] S&P, Corporate Ratings Criteria, 2003, pages 44-45.

In other words, there is a cross subsidy from the regulated to the unregulated entity *unless* the regulated entity is "ring fenced" so that any problems on the non-regulated side do not impact the regulated side. S&P refers to this as "structural insulation techniques" which may involve:

- separate incorporation of the sub
- independent directors
- minority ownership stakes
- regulatory oversight to insulate the subsidiary
- restrictions on holding company cash management programs

Consequently, double leverage can not just transfer the tax advantages to the parent's shareholders, but it also may result in lower bond ratings and a higher debt cost for the operating utility. As a result, utility ratepayers lose part of the debt tax shield and to add insult to injury may also pay for a higher cost of debt, thus getting hit twice.

Q. IS THIS RELEVANT FOR THE QUEBEC UTILITIES?

A. Not to the same degree that it is for other operating companies within a UHC. However, the senior management still has a fiduciary duty to its shareholders to enhance shareholder value. This could mean taking steps at the parent level that effectively transfer value from ratepayers to shareholders: increasing the common equity ratios of the Quebec utilities is consistent with this ownership pattern.

Of note is that the DBRS bond rating for Energir is A, but this includes the impact of its ownership of Vermont Electric Power, 50% of TransQuebec and Maritimes (TQM) pipeline and other sundry assets. In its 2021 rating report DBRS notes that the consolidated debt ratio for Energir is 67.2% which means its equity ratio is only 32.8% far below Energir's regulated 46% total (common plus preferred) equity ratio. The fact that Energir primarily finances with first mortgage bonds and other secured debt acts as ring fencing to protect rate payers, as does restrictions in Energir's non-regulated assets.

Similar comments apply to Gazifere, where it is treated as a BBB (low) issuer in the debt supplied by Enbridge, yet it is the responsibility of the same senior executive as Enbridge Gas Inc in Ontario, suggesting that it is viewed as an integral part of the same distribution system[9],

[9] Gazifere refused to answer questions related to its integration with Enbridge Gas Inc.

yet Enbridge Gas has a deemed 36% common equity ratio, not the requested 45% for Gazifere. Allowing Gazifere and Energir's requested common equity ratios will simply transfer more debt capacity to their parents.

Q. HOW DO YOU RECOMMEND THE REGIE SET COMMON EQUITY RATIOS?

A. The most basic determinant of a utility's common equity ratio is its business risk. In RH-2-94 the National Energy Board stated (Decision page 24)

> "The Board is of the view that the determination of a pipeline's capital structure starts with an analysis of its business risk. This approach takes root in financial theory and has been supported by the expert witnesses in this hearing. Other factors such as financing requirements, the pipeline's size and its ability to access various financial markets are also given some weight in order to portray, as accurately as possible, a complete picture of the risks facing a pipeline"

Seven years later in RH-4-2001 the Board considered TransCanada's business risk and concluded (page 24)

> Summary
>
> Overall, the Board concludes that the level of business risk facing the Mainline has increased since 1994, although it remains low. The increased business risk primarily reflects an increase in the risk resulting from pipe-on-pipe competition and increased supply risk. Other sources of risk have not changed materially.

This was based on the Board's assessment of five aspects to business risk:

- Pipe on pipe competition,
- Market (Demand) risk,
- Supply risk,
- Regulatory risk,
- Operational risk.

The NEB therefore increased the Mainline's common equity ratio to 33%, which has subsequently been increased to 36% and then 40%.

Before the Alberta EUB in 2003 I compared the different utilities in the Alberta generic hearing on the following basis:

I: The major ***short-term*** risks caused by cost and revenue uncertainty:

- On the cost side since regulated utilities are capital intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.

- On the revenue side the risks largely stem from rate design, critical features are:

  - Who is the customer and what *credit risk* is involved? For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments from the provincially appointed TA, who is responsible for system integrity, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.

  - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.

  - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

II: The ***medium and long-term*** risks are mainly as follows:

- *Bypass risk*. The economics of regulated industries are as natural monopolists involved in "transportation" of one kind or another. However, one utility may not own all the transportation system so that it may be economically feasible to bypass one part of the system. This happens for local gas distributors, when a customer can access the main gas transmission line directly, rather than through the LDC, or when a large customer may be able to bypass part of the transmission system. This is often a rate design issue: a postage stamp toll clearly leads to uneconomic tolls and potential bypass problems, whereas distance or usage sensitive tolls will discourage it. Similarly, rolled in tolling will encourage predatory pricing by potential regulated competitors.

- *Capital recovery* risk. Since most utilities are transportation utilities, the critical question is the underlying supply and demand of the commodity. If supply or demand does not materialise, then tolls may have to rise, and the utility may not be able to recover the cost of its capital assets. Depreciation rates are set to mitigate this risk to ensure that the future revenues are matched with the future costs of the system.

A common thread running through the above brief discussion is rate design. There can be significant differences in underlying business risk that are moderated by the regulator in response to those differences. The lowest risk utility is then one with the strongest underlying fundamentals and the least need to resort to regulatory protection. In contrast, another utility may have similar short-term income risk, but only because of its need to resort to more extensive regulatory protection, so that it faces more problematic long-term risks.

On that basis and at that time I judged the lowest risk regulated utilities in Canada to be electricity transmission assets, since they had the following characteristics:

- Minimal forecasting risks attached to O&M
- Revenue recovery via the Transmission Administrator as a fixed monthly charge
- Limited (non existent) by-pass problems
- Minimal capital recovery problems, since there are many suppliers of electricity as a basic commodity.
- Deferral account for capital expenditures

and recommended 30% common equity ratios similar to the mainline gas transmission pipelines in RH-2-94.

I then placed the gas transmission pipelines as the second lowest risk group. Here I classified Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to electricity transmission assets with NGTL having marginally more risk than Foothills and the TCPL BC System, since it was exposed to bypass risk and recovered its revenues through a forward test year from a greater variety of shippers. I therefore judged that on its own NGTL could maintain its financial flexibility on the same 30% common equity ratio allowed mainline gas transmission assets. However, because NGTL was then allowed 32% and was almost “indistinguishable” from the TCPL Mainline, I recommended the same 33% common equity ratio then allowed the Mainline.

I then judged the local distribution companies (LDCs), including both gas and electric as the next riskiest. These companies were distinguished by their retail operations, which mean that their revenues are recovered from a large number of industrial, commercial and residential consumers. This exposes them to both the business cycle and weather fluctuations. This revenue recovery is largely a function of their rate design that may expose them to commodity charges and a fixed and variable recovery charge. Within this group the conventional yardstick for LDCs was that Enbridge Gas Distribution Inc and Union Gas were both allowed 35% common equity by the Ontario Energy Board. In contrast, whereas the Ontario Energy Board allowed a purchased gas variance account (PGVA) to ensure that the full costs of gas were recovered, both were still subject to volume variances due to weather. In contrast, the BCUC through its RSAM removed this risk from BC Gas (Terasen Gas, now FortisBC Gas)), but only allowed it a 33% common equity ratio. With these yardsticks, I recommended a 35% common equity ratio for a typical local distribution company.

Finally, I recommended 42% as the upper end of a reasonable range for the common equity of ATCO pipelines, given that the BCUC allowed PNG, a smaller and much riskier pipeline, 36% common equity. However, this ranking was provisional being dependent on the EUB developing clear rules on intra Alberta pipeline competition and a rate design that lowered ATCO Pipeline's risk. Further it was my judgement that none of the Alberta utilities were as risky as Pacific Northern Gas (PNG) with a 36% common equity ratio or Gaz Metro (GMI) with a 38.5% common equity ratio, where I regarded those two as the riskiest regulated utilities in Canada.

Q WHAT DID THE EUB ALLOW?

A. The AEUB's decision can be summarised in the following table:

Table 13 Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A	39.0	N/A
EPCOR DISCO	N/A	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

The AEUB's risk ranking was essentially the same as mine although they allowed higher common equity ratios than I recommended. Electricity transmission facilities operators (TFO) were allowed 33% common equity, NGTL was next with 35%, then electric distributors with 37%, gas distribution 38% and finally ATCO pipeline was allowed the highest common equity ratio at 43%. In each case non-taxable utilities were allowed more common equity due to the absence of the dampening effect of corporate income taxes. AltaGas is a very small rural utility and was allowed 41% common equity due to its small size. With risk adjusted through the common equity ratio the Alberta EUB then allowed all the utilities the same ROE determined through an annual adjustment mechanism like that allowed by the NEB.

Q. WHAT IS YOUR VIEW ON REGULATORY RISK?

A. I have not explicitly mentioned regulatory risk, since in my judgment it is a gross misnomer to refer to regulation in Canada as a *risk*. In my judgment the nature of regulation in Canada has been to protect the utility. I have heard many company witnesses discuss "increases" in risk faced by various regulated utilities since I first testified in 1985. However, the ability of Canadian regulated utilities to earn their allowed ROE has not been impaired and I have yet to see ***any*** of these risks materialise to significantly harm a Canadian utility. *In this respect it is my judgement that the risks brought forward on behalf of the companies in this hearing, as in every other hearing for almost the last four decades have, or will be, largely transferred to ratepayers if they ever materialise.*

The history of regulation in Canada is that when risks are invariably transferred to rate payers as part of the dynamics of regulation. This dynamic is illustrated through:

- the adoption of forward test years,
- the removal of the commodity charge through fuel pass-throughs,
- the removal of the merchant function,
- the adoption of weather- related deferral accounts,
- increasing focus on the core service where the utility has market power,
- the reduction in regulatory lag,
- increased fixed charge component in rates,
- the adoption of ROE formula adjustments,
- review of depreciation studies when stranded asset risk changes,
- prior approval for significant new capital additions,
- flexible hearings to review unique risks.

All these policies have served to reduce the risk of regulated utilities in Canada. The fact is that regulation is a flexible process that moderates or shares these risks even if they do materialise to the extent that the regulated utility is rarely hurt. A case in point is Pacific Northern Gas (PNG) in 2006, which at the time I regarded as the riskiest regulated utility in Canada.

There is no doubt that in 2006 PNG was extremely risky. It operated a tiny 600 kilometre pipeline from the Westcoast Transmission system through to Western British Columbia, where the economy was at the time heavily dependent on forest products and a few cyclical industries. Until November 2005 almost 70% of PNG's throughput went to a few industrial customers with one, Methanex, overwhelmingly important. Unfortunately, Methanex closed its doors in November 2005 and PNG lost the load. Such a loss of load dwarfs anything that could conceivably affect Gaz Metro.

How did the BCUC respond to PNG's serious problems? In the first place the BCUC allowed PNG a 0.65% premium to the ROE as well as more common equity than that allowed its low-risk benchmark (BC Gas then Terasen Gas now FortisBC Gas). These more favourable financial parameters have been allowed on an ex-ante, or before the fact basis, to reflect PNG's potential problems, since the risks attached to PNG's dependence on a limited number of industrial customers had been known for a long time. That is, PNG's shareholders were rewarded for its greater risk ex ante or before they materialised. However, as the risk increased the BCUC then allowed PNG a series of deferral accounts. First a comprehensive revenue stabilisation adjustment mechanism (RSAM) to remove weather induced variability in PNG's earnings. Second an industrial customer deliveries deferral account (ICDDA) to recover any deviations of actual deliveries from those forecast for PNG's large industrial customers. PNG also took $5.05 million of Methanex related assets out of its rate base and put these into a special deferral account to be recovered from other customers over a ten-year period. Finally, the BCUC approved in principle the conversion of PNG into an income trust to help reduce costs.

The important fact to note is the active participation of the regulator, the BCUC, in helping PNG cope with a huge company threatening event. For example, although Methanex accounted for 62% of PNG's throughput the BCUC allowed PNG to offer a special discount rate for Methanex and rebalance its rates. As a result, before it closed Methanex only accounted for 7.6% of PNG's operating revenues, even though it was 62% of PNG's throughput. As the Methanex related assets are recovered from other customers it emphasises the fact that a regulated utility only faces two basic risks: short run forecasting risk and the possibility of a "death spiral."[10]

The example of PNG illustrates the basic proposition that regulation shields the utility from many of the problems it ostensibly faces. The reason is that should these risks arise the utility invariably goes to the regulator and gets the costs allocated to ratepayers. Another example is the potential liability to EGDI caused by the Supreme Court of Canada with respect to a 5% late payment penalty, a penalty which breached the criminal code in terms of a fair rate of interest. On page 3 of the October 31, 2006, MD&A EGDI simply states,

> ***"The company intends to apply to the OEB for recovery of the proposed payments resulting from the settlement of this action."***

That is, that the settlement of this liability would not be paid by shareholders but simply passed on to ratepayers. Further in 2008 the OEB did allow EGDI to recover these costs and was supported in this decision by the Consumers Association of Canada.

Yet another more recent example is Newpage one of Nova Scotia Power's largest customers with operations in Port Hawkesbury, Nova Scotia which went bankrupt in September 2011. In a settlement the assets dedicated to these operations were to be reallocated to other customers. However, in September 2012 a modified load retention tariff was approved to ensure the plant covered incremental costs, as well as contributing to non-fuel costs. As a result, Newpage's plan of arrangement was finalised and it emerged from creditor protection.

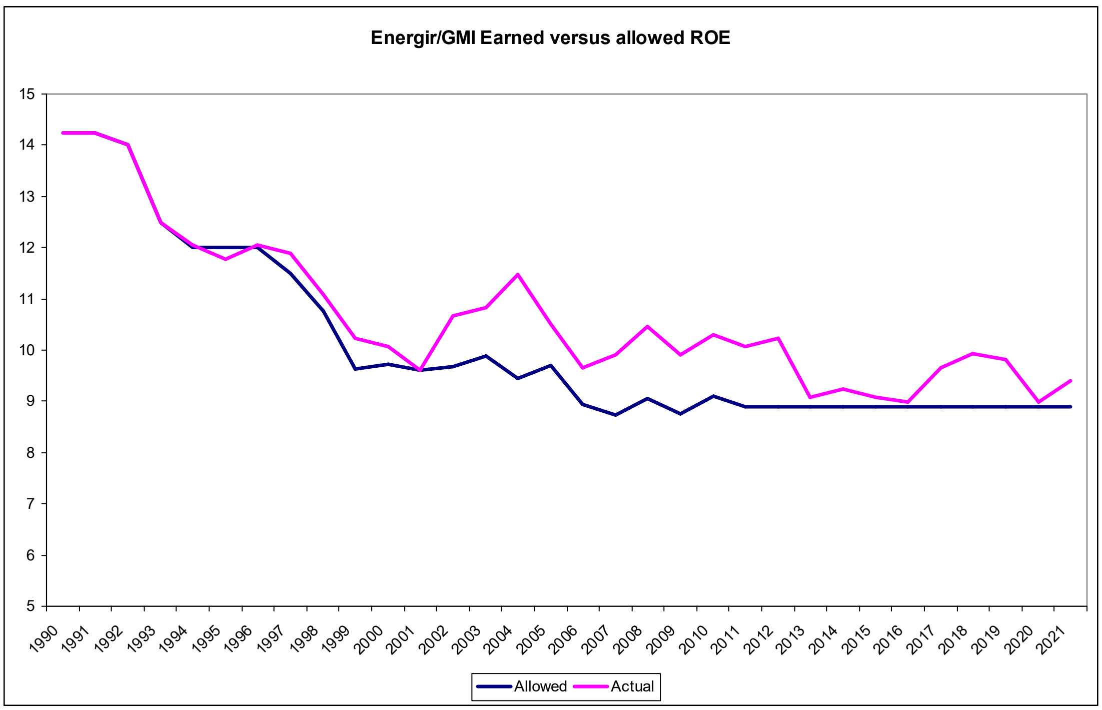
These examples demonstrate the dynamics of Canadian regulation and that risks often identified as risks faced by utility shareholders end up with ratepayers.

Q. WHAT IS THE SHORT RUN RISK FACED BY THE QUEBEC UTILITIES?

A. The dictionary definition of risk is the possibility of harm, where in finance we normally think of it as losing money. In the case of regulated utilities this translates into the probability of not earning the allowed ROE. In answer to the filing request of the Regie (EGI-15) the Quebec

[10] Note the shareholders investing in the shares of a utility also suffer market risk and interest rate risk. So, this is not to say the shares are risk-less.

utilities provided their earned (actual, realised) ROE and their allowed ROE back to 2002. I then matched that for Energir with GMI's answers to previous information requests for the same data and graphed it as below.[11] In the entire 32-year history, Energir/GMI only failed to earn its allowed ROE once in 1995, and they failed to provide an explanation for that deviation. Over the entire period Energir over earned by an average of 0.58%. However, some of this was due to incentive regulation from 2001 to at least 2009. However, regardless there has been no indication of any risk borne by Energir's shareholders in terms of failing to earn their allowed ROE.

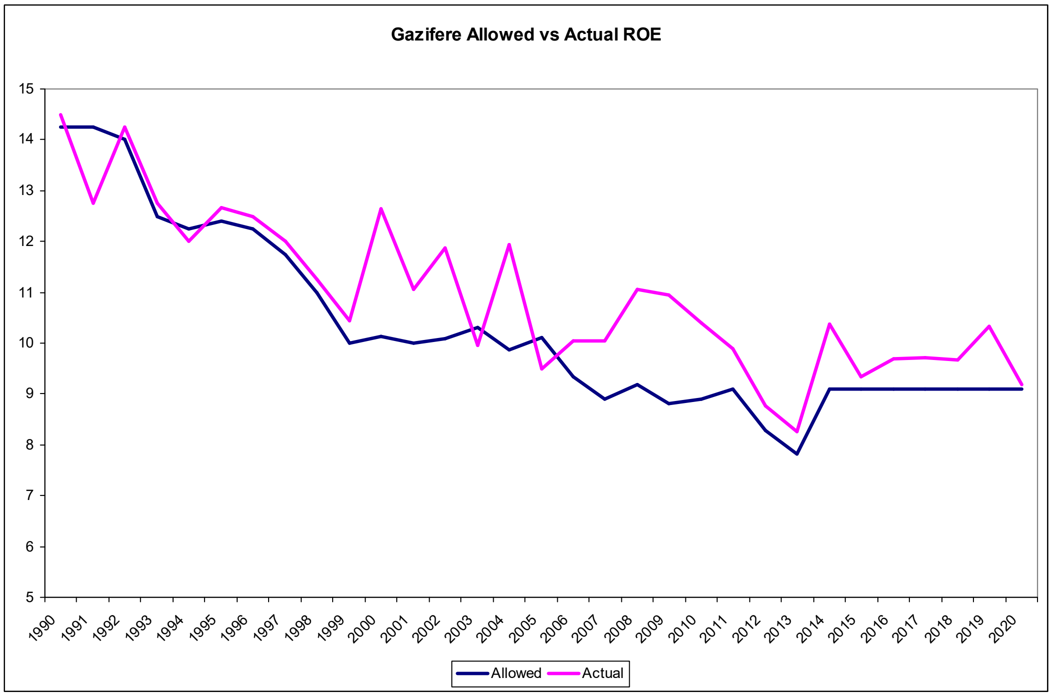


Gazifere also provided its earned versus actual history and matching this to the answers given in 2010 (GI-31 & GI-32) to this data generates a series back to 1990.[12] The earlier data is the earned ROE after sharing gains with ratepayers. In some cases, these values are significant. In

[11] I asked Energir for the data inclusive of any incentive return, but they declined to provide the information or an explanation for any deviations. This answer is under review.

[12] There are some data inconsistencies between the data provided in 2010 and the more recent series. Where the series overlap, I have used the most recent data provided to the Regie.

1992, for example, Gazifere earned 18.40% before sharing, but only 14.25% after sharing.[13] Similar to Energir the following is the graph of the actual versus the allowed ROE.



On average and even after sharing Gazifere earned 0.66% more than allowed. This is marginally higher than Energir. Gazifere has failed to earn its allowed ROE on 5 occasions, but interestingly neither utility has failed to earn its allowed ROE since 2005. In my judgment neither utility has experienced any risk in practical terms for a very long time.

Q. ISNT ENERGIR RISKY DUE TO ITS HIGHER SHARE OF INDUSTRIAL VOLUMES?

A. Traditionally the risk attached to distribution utilities has partly been based on the share of their revenues coming from industrials, versus commercial versus residential customers with industrials the riskiest customer group. However, this depends on the contracting relationship between different groups. In the case of Energir, DBRS points out that this is a “challenge” but also that 80% of all industrial volumes are contracted based on firm service contracts of at least one year’s duration. Consequently, there is limited short term forecasting risk in firm service.

[13] I requested any incentive ROE in addition to the allowed, but Gazifere did not provide it, so the series are difficult to reconcile. This answer is also under review.

Gazifere has a heavily residential customer base with limited exposure to industrial customers. In both cases, the loss of load from industrial customers beyond the one-year forecasting period can be offset by rebalancing rates. As a result, Energir's heavier industrial load (60%) is more a long term than a short term risk. Moreover, there is no evidence that Energir's higher industrial load has made it more difficult for Energir to earn its allowed ROE.

Q. WHY DO GAZIFERE AND ENERGIR CONSISTENTLY EARN THEIR ALLOWED ROE?

A. Both operate on a forward average test year basis with frequent rate hearings, so the only risk is the forecasting risk involving revenues and cost. This forecasting risk can be managed by trimming expenditures, for example, towards the end of the year if there are unusual expenditures earlier in the year, but in practise the use of deferral accounts removes even this minor risk. As the old saying goes "the proof of the pudding is in the eating" and in this case consistently over earning their allowed ROE indicates the absence of short-term risk.

Q. WHAT ABOUT INTRAGAZ?

A. Intragaz is owned 50:50 by Engie Quebec Inc and its only customer Energir. Further its revenue requirement is a cost of service for Energir so in practical terms the only risk it faces under the existing contract is non-payment. There is always a risk that the contract is not renewed but if Energir needs to balance its load off the TQM system with its seasonal demand it will need storage. Intragaz's storage assets now have over 20 years of operational life with minimal problems where the main risk in a depleted gas reservoir used for storage is construction risk, which is now long past.[14]

In 2012 I pointed out the inherent conflict of interest that Gaz Metro is both the part owner and customer so the only risk, that of non-renewal, however slight, should not be used to justify a higher ROE that will in part be earned by Gas Metro (Energir).[15] As I indicated in 2012 I regard these assets as indistinguishable from other distribution assets owned by Energir apart from the

[14] Note Intragaz is not using its storage at a major pipeline intersection as is the case with several competitive US companies.

[15] This vitiates any suggestion that Intragaz be regulated as a "stand alone" utility.

fact there is a significant minority interest. Consequently, I have no trouble Intragaz being allowed the same financial parameters as Gaz Metro (Energir).

Q. DOES THIS MEAN THE QUEBEC UTILITIES HAVE NO BUSINESS RISK?

A. No. I agree with the Canadian Energy Regulator when they stated (RH-2-94, page 25)

> *"With regard to the argument that regulation shields pipelines from risk, the Board believes that its regulation provides pipelines with a degree of assurance of cost recovery which is absent for non-regulated industrials. However, the Board believes that the realities of market forces cannot be discounted when addressing pipelines' business risks."*

Essentially market forces may prevail and overwhelm the regulator's ability to protect the utility. This was the major focus of the landmark hearing in 2012 into the TransCanada Mainline when due to the development of alternative supply basins to the WCSB, there was a fear at the time that the Northern Ontario Line may be stranded. So, whereas factors like operational risk are short-term, in the long run risk comes from the supply and demand for the commodity being distributed.

Q. WHAT ABOUT THESE LONG RUN RISK?

A. To some extent the name long run risk is a misnomer since the long run is simply the future succession of short runs. However, there may come a time when a utility suffers a loss of customers and this revenue can not be recovered by shifting to other rate classes, as the rates would be too high. In such a situation we would get the "death spiral" as rates rise to recover revenue losses more customers drop off the system and eventually the utility can not raise rates enough to earn its fair return and it may even fail to earn enough to recover the return of capital through depreciation.

Note that the trigger for such a situation is an inability of a utility to earn its allowed ROE and rebalancing rates. This must occur for there to be in any long run risks. The fact that the Quebec utilities have so far had no problems earning their allowed ROEs is prima facia evidence that there so far there has been very little, long run risk.[16] Further evidence comes from examining

[16] A qualification is that they may have had to ask for more regulatory protection, that is, dip into some of their latent market power.

the key question of whether rate base assets are likely to become stranded, that is, whether there is a realistic possibility of a death spiral.

Q. WHO BEARS THE STRANDED ASSET RISK?

A. This remains a contentious issue and I would caution that I am not a lawyer so all I can offer is an economist's interpretation. However, the Stores Block decision of the Supreme Court in Canada in 2006 made a far-reaching decision that regulation of a utility essentially transfers the service rights of the assets to ratepayers, but not the ownership rights, which remain with the shareholders. The AUC interpreted this decision as follows:[17]

> "***The Stores Block decision confirmed that the assets used for utility service are the property of the utility service provider. Customers pay for utility services, which are priced to recover the reasonable costs (including a return on investment) associated with the assets providing those services. However, in paying for utility services, customers do not acquire an ownership interest in the underlying assets. Further, these property and corporate law principles symmetrically allocate to the utility the benefits and risks of property ownership. A literal application of these fundamental principles, as subsequently directed by the courts, would allocate all benefits and risks to the utility shareholder in a symmetrical manner with the shareholder retaining all gains on sale and any benefits from the redeployment of utility property for non-utility purposes as well as absorbing any losses on sale and the costs of any unrecovered capital associated with assets that cease to be used or required to be used in providing utility service. Any gain or risk of loss with respect to the utility's original investment would be for the account of the owner of the property in a symmetrical manner consistent with the principles of property ownership and corporate law.***"

The key to understanding the Stores Block decision and how it is interpreted, at least by the AUC, seems to be the word "unrecovered" capital, which is to say the undepreciated book value of the assets at the time they ceased to be used and useful. This requires a timely depreciation study to ensure that the economic planning horizon (EPH)[18] over which the asset is to be used and useful and thus depreciated is up to date, so that the asset's cost is assigned as a service cost

[17] D 21609-D01-2019, page 23. This decision is currently under appeal.

[18] Note the EPH is not an engineering assessment of how long the pipe will last, but how long it will be economically used and useful.

to the ratepayer. If an asset is retired in an extraordinary way as was claimed in the above decision of the AUC, then the loss is to the account of the shareholder.[19]

With the Supreme Court of Canada's decision in mind I would expect a Canadian utility to revisit the economic planning horizon of its rate base assets to ensure its depreciation rate recovers the value of its rate base assets. As a result, I would expect that an increase in stranded asset risk would show up in a shorter economic planning horizon and higher depreciation rate. This judgment is consistent with the decision of the National Energy Board when the Mainline was first confronted with pipe-on-pipe competition coming from new US gas fields closer to its Central Canada markets in Ontario and Quebec. In relation to depreciation in RH-4-2001 the Board stated (page 28)

> The Board views the issues of cost of capital and depreciation as being related, but as addressing different factors. The primary goal of a depreciation rate is to reflect the assessment of the economic life of an asset. Business risk, which is a key determinant of cost of capital, addresses the probability that the utility may not be able to recover its prudently incurred costs over the economic life of the asset, whatever that economic life may be.

I would interpret this statement as meaning that the Board tries to get the economic planning horizon or depreciable life correct, to maintain a constant stranded asset risk. With a constant risk of recovering its rate base assets the utility can be awarded the same fair rate of return.

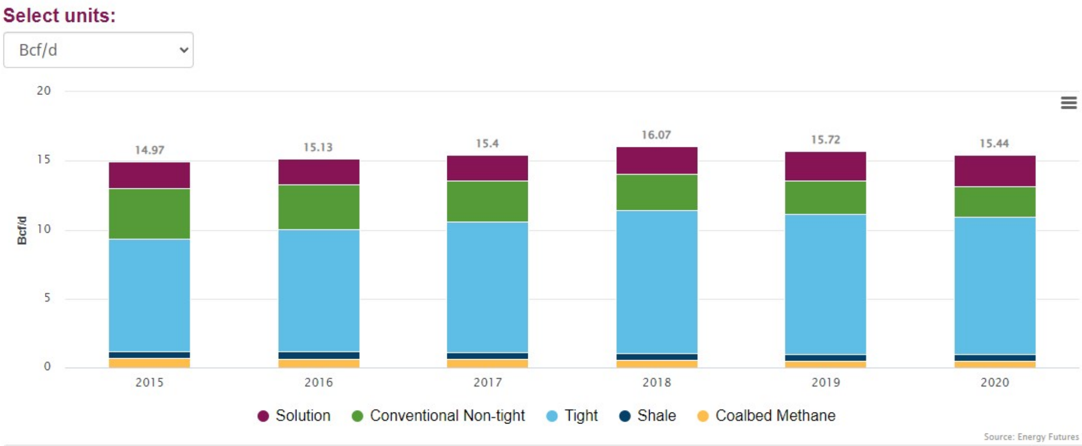
Q. HAS THE ECONOMIC PLANNING HORIZON FOR THE DISTRIBUTION OF GAS CHANGED?

A. That's very difficult to determine as I don't have access to a recent depreciation study for Energir and Gazifere. When I asked for one in 2009 the then Gaz Metro produced a July 2000 study indicating a significant lag between that study and the rates hearing.

However, stranded asset risk depends on supply and demand and what is a fact is that production in western Canada is not significantly declining. The following graph is from the Canadian Energy Regulator and compared to forecasts at the time of the GMI 2009 and 2011 hearings Canadian gas supply is slightly above those forecasts.

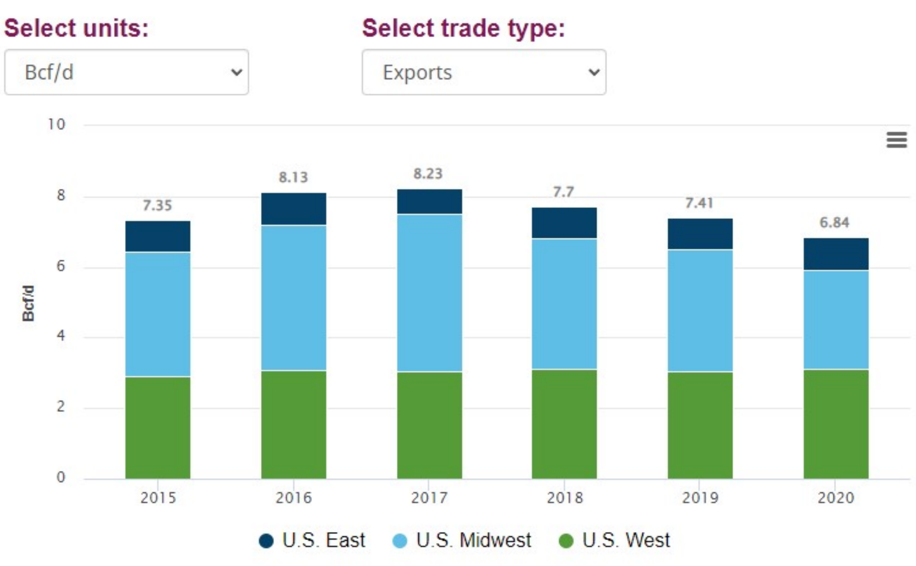
[19] My understanding is that the loss was due to "extraordinary" wildfires in Northern Alberta in 2016 that destroyed $15 million of ATCO Electric's rate base assets.

Figure 16. Total Western Canada Sedimentary Basin Production



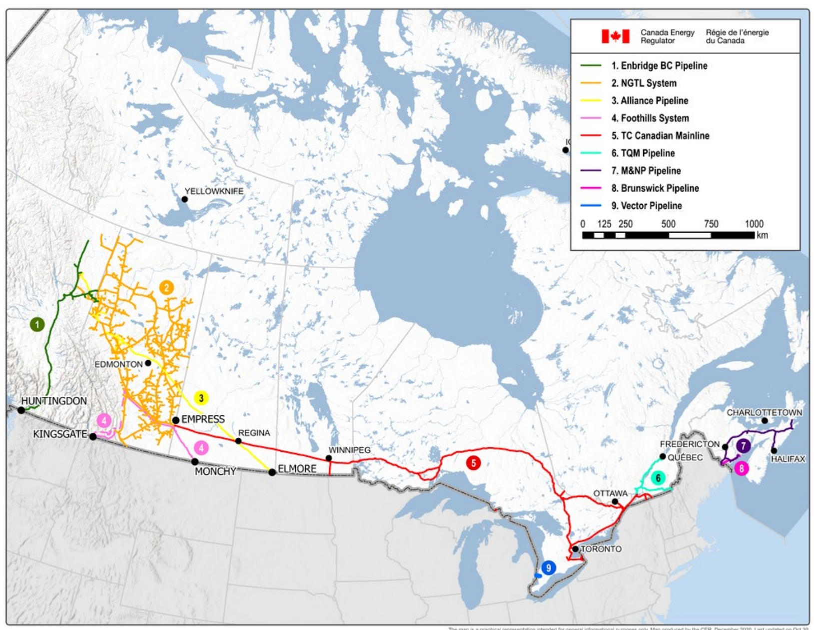
Export sales to the US are a significant component of Canadian gas production as indicated below. By subtracting export from total supply there is an indication that the supply to Canada has grown from approximately 7.62 bcf a day to 8.6 bcf a day with the largest components demand from the Alberta Oil Sands and industrial demand.

Figure 17. Natural Gas Exports from Canada to U.S. Region



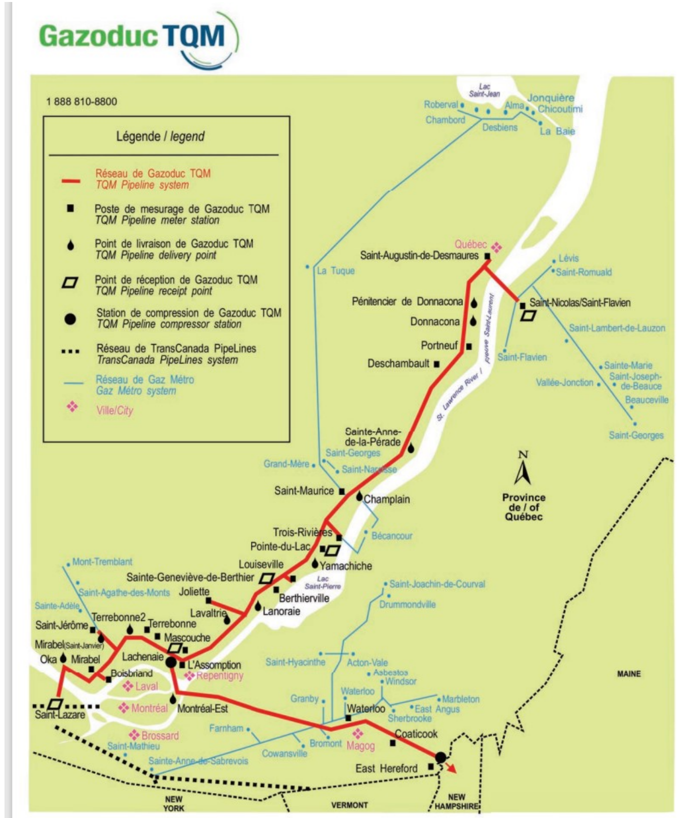
With supply not significantly different from previous hearings the only factor affecting stranded asset risk is demand. What is important is that shifts in demand affect not only the gas distributors in Quebec, but also the mainline transmission system delivering gas to them. If the distribution pipe is stranded due to a collapse in demand and faces a death spiral, then there are obvious knock-on effects for the pipeline serving them.[20] Below is the Canadian Energy Regulator's map of Canada's pipeline system. What is important to note is that the eastern "end of the line" of the TransCanada Mainline is when it becomes the TQM pipeline. So that to a great extent the viability of TQM depends on the viability of natural gas demand in Quebec. There is limited throughput to East Hereford, but essentially TQM depends on Quebec's demand for natural gas.

Figure 15. Major CER-Regulated Natural Gas Pipelines



The TQM system map is below

[20] Canada is the sixth largest gas producer in the world and the CER has approved several new pipelines over the last five years mainly in the BC segment of the WCSB. In Quebec Gazoduq is planning a new $5 billion mainline to transmit natural gas from Northeast Ontario to the Saguenay to export natural gas and contribute to the reduction in greenhouse gas emissions worldwide.



It is clear from TQM's map that it provides system gas to Energir throughout most of Quebec and the two are closely integrated.[21] This is also why Energir owns 50% of TQM with the other 50% owned by TransCanada. What is important is that TQM just filed a settlement agreement with the Canadian Energy Regulator which was approved in 2022. This settlement included an up-to-date depreciation study prepared by Concentric Advisors ULC. One of the key facts on which the depreciation study was based was (page v)

> 19. Concentric developed the depreciation rates utilizing the Economic Planning Horizon (EPH) dates of 2050 and 2040 for the Québec and East Hereford segments of TQM, respectively. The service life of each of these geographic segments are distinct as contract terms, flow volumes and market dynamics are sufficiently different as to warrant separate segments with different EPHs. TQM's previous depreciation study,[10] completed in 2009, also segmented the Québec and East Hereford lines using 2050 and 2023 EPHs, respectively. Concentric continues to recommend the calculation of depreciation rates based on these two distinct geographic segments, with an extended EPH for the East Hereford segment relative to the previous depreciation study.

[21] Gazifere is integrated with Enbridge and receives its supply from Enbridge and the TransCanada Mainline.

The important implication for the Concentric study adopted by TQM is that there has been no change in the economic planning horizon for the Quebec rate base assets as it remains the same 2050 date as in 2009, despite changes that might be argued will occur in the demand for natural gas before 2050. Also, the economic planning horizon for the East Hereford rate base assets has increased from the 2023 to 2040, that is, those rate base assets are now expected to have an economic life *longer* than assumed in 2009. With no change in the economic planning horizon the depreciation rates are substantially unchanged; the depreciation rate on the mains is 1.32% for Quebec and 2.49% for East Hereford with a composite rate of 1.69%. Consistent with the CER (then NEB) 2001 decision on the Mainline an unchanged depreciation rate implies an unchanged business risk assessment for the mainline pipe serving Quebec and by implication the distribution pipe off the mainline pipe.[22]

Q. WHAT ABOUT CLIMATE CHANGE AND PROVINCIAL POLICY TO REDUCE GREENHOUSE GASES?

A. To be a risk factor climate change must affect either the probability of the Quebec distribution utilities earning their allowed ROE or the possibility of a death spiral. The former is under the control of the Regie and requires a change in what I understand has been regulatory policy in Canada for decades to protect the utility. Instead, it requires that the Regie reverse existing policy and deliberately put the utilities at risk, which I don't see happening. The latter requires that the incumbent Quebec utilities formalise a plan to respond to climate change and bring it to the regulator in a hearing so the implications can be assessed by interveners and the Regie. Now I see no evidence on the record except broad statements about climate change and customers under pressure to switch to electricity from natural gas. However, I do not see a comprehensive plan indicating explicitly how this affects the utilities, which is also the position of Dr. Hopkins and which I fully support. [23]

Change is always a bit unpredictable, except that the history in Canada is that change rarely hurts the utility since it is a dynamic process and long run risks eventually become short run risks that

[22] There may be some slightly greater risk for the distribution pipe which is why traditionally I have used a 35% common equity recommendation for a distributor and 30% for mainline. This is because there is greater stranded asset risk for small pipes off the mainline than for the mainline itself while the mainline is normally backstopped by long term contracts.

[23] Dr. Asa S. Hopkins, On the topic of business risk, April 8, 2022.

can be dealt with in a hearing. A good example of this regulatory dynamic was a decision of the Ontario Energy Board (EGDI Decision 2013-0207, page 7) where the OEB stated

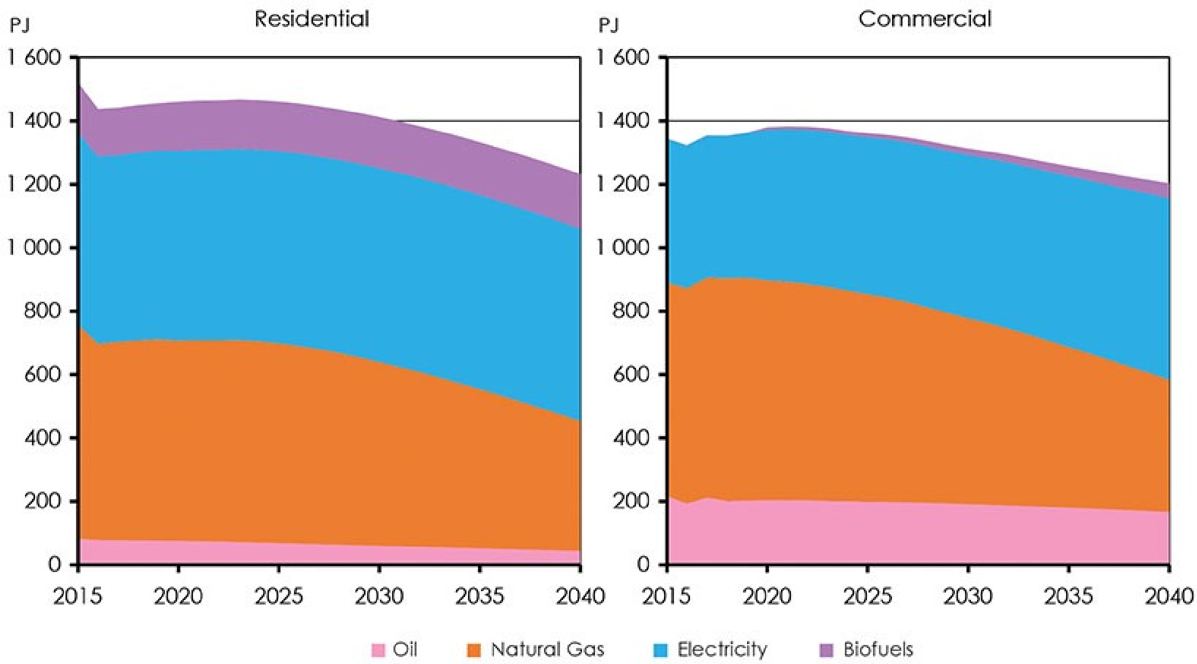
> ***"Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."***

In essence the OEB decision is to 'not pay too much attention to long run risks as we'll deal with them as they arise'. On this basis I can see nothing in the expert testimony filed on behalf of the Quebec utilities that would lead me to believe that they will not earn their allowed ROE in the next 3-year test periods.

Longer-term there are problems to deal with, such as the increase in the carbon tax each year of $15 per tonne to reach $170 by 2030. This translates into $1.96 cents per cubic metre for natural gas and reduces the significant cost advantages that heating with natural gas enjoys, particularly in the residential sector. However, longer-term there are also opportunities. FortisBC Energy for example, has a target of 30by30, which is to say a 30% reduction in greenhouse gas emissions by its customers by 2030 and on January 20, 2022, before the BCUC proposed 100% RNG for every newly constructed home. The clear intent of FortisBC Gas is to continue to capture the heating market for new builds in a province also facing intense competition from electricity. Similarly, Enbridge Gas (EGI)[24] recently implemented a voluntary $2 charge to purchase low-carbon RNG rather than system gas in a province where the use of natural gas is still expanding with new rate base assets. The fact is that the demand for natural gas is not going to disappear any time soon as the following projection by the Canadian Energy Regulator forecasts even under its "technology" case. Consequently, I recommend that the utilities be asked to file specific testimony on how provincial climate change regulations will affect their business risk at their next rate hearing. Now, I would regard the risks faced by climate change to the Quebec utilities as being speculative.

[24] This is the amalgamation of Enbridge Gas Distribution Inc and Union Gas. Details from EGI's February 11, 2022, AIF where natural gas enjoys a huge cost advantage over other fuels.

Figure 4.18: Residential and Commercial Demands by Energy Source, Technology Case



Q. IS THERE EXTERNAL SUPPORT FOR YOUR CONCLUSION?

A. Yes. There have been concerns about climate change for some years, yet this has not been reflected in the bond rating reports by either DBRS or S&P for Energir. S&P's high-level analysis is below where they give Energir the highest possible business risk profile of "excellent".

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

In terms of environmental risk S&P states

> ***We view Energir's exposure to environmental, social, and governance-related risks as similar to the broader industry. The company is primarily a gas distributor but also owns an electric regulated transmission and distribution network. For natural gas network operators, environmental risks include gas leaks and explosions and emission of greenhouse gases (GHG), which can affect biodiversity. We believe Energir's environmental risk is consistent with the broader industry because the company's gas network is fairly new and does not contain cast iron or bare steel pipes which reduces the potential of gas leaks and explosions. In addition, the company also participates in the Quebec's cap-and-trade system, to offset its GHG footprint in its gas distribution operations.***

DBRS has no discussion of environmental risk in its 2021 rating report on Energir.

Overall, and consistent with both DBRS and S&P, I see no material change in the business risk of any of the three Quebec utilities.