Prepared Direct Testimony

of

J. Stephen Gaske

On Behalf of Intragaz Limited Partnership

June 25, 2012

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I. INTRODUCTION

Q.1 Please state your name and business address.

A. My name is J. Stephen Gaske. My business address is 1130 Connecticut Avenue, Suite 850, Washington, DC 20036.

A. Qualifications

Q.2 Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates ("HZA") as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986, I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986, I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986, I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988, I returned to HZA and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors ("Concentric") and I became a Senior Vice President of Concentric.

Q.3 Have you presented expert testimony in other proceedings?

A. Yes. I have filed expert testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations in numerous proceedings before: the U.S. Federal Energy Regulatory Commission ("FERC"), eight state regulatory bodies, the Alberta Utilities Commission, the Ontario Energy Board and before the Comisión Reguladora de Energia de México ("CRE").

In addition, I have testified or submitted expert testimony on regulatory principles, economics, and pricing issues before the FERC, the National Energy Board of Canada, 12 state and provincial regulatory Commissions, and the U.S. Postal Rate Commission. Topics addressed before those regulatory bodies have included regulatory principles, utility and energy economics; electric utility and gas pipeline cost allocation, rate design, pricing, and revenue requirements; market power; and, generating plant economics.

During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on commercial, economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association, the Financial Management Association, and the American Finance Association.

B. Summary of Testimony

Q.4 What is your assignment in this proceeding?

A. I have been asked by Intragaz Limited Partnership ("Intragaz") to recommend a rate of return on common equity and the appropriate capital structure to be used in setting cost-based rates in this filing, and to calculate the overall cost of capital for Intragaz. In this testimony, I (i) discuss the regulatory principles that should be applied in setting Intragaz' regulated rates; (ii) recommend a ratemaking capital structure; and (iii) calculate the cost of common equity capital for Intragaz' natural gas storage operations. My cost of capital determination is based on the results of my Discounted Cash Flow (DCF) analysis of a group of Canadian utility companies and is supported by the DCF results of a proxy group of U.S. natural gas pipeline and storage companies. Both proxy groups are subject to slightly less risk than Intragaz's natural gas storage operations. My results are further corroborated by a risk premium analysis. My selection of proxy companies is based upon a detailed examination of the comparability and risks of each of the operations of a potential proxy company, and an assessment of whether the risks of each of the potential proxy companies are comparable to those of Intragaz. I then consider the differences between Intragaz' risks and those of the proxy companies in arriving at a recommended rate of return on common equity.

Q.5 What testimony and schedules are you sponsoring?

A. I am sponsoring the following testimony and schedules, which were prepared by me or under my direction supervision:

Prepared Direct Testimony of J. Stephen Gaske

Schedules to Prepared Direct Testimony:

Schedule 1	Economic Statistics and Bond Yields
Schedule 2	Proxy Company Statistics
Schedule 3	Gas Transmission Pipelines and Storage Owned by Proxy Companies
Schedule 4	Proxy Company Business Segment Data
Schedule 5	Calculations of Dividend Yields
Schedule 6	Growth Rates
Schedule 7	DCF Results
Schedule 8	Flotation Cost
Schedule 9	Capital Structure
Schedule 10	Calculations of Median Results

Q.6 Would you summarize the primary conclusions of your testimony in this proceeding?

A. The primary conclusions of my testimony are:

1) Established regulatory principles require that Intragaz be given an opportunity to earn a reasonable return on its invested capital. [Section II. A.]

2) In order for regulated rates to be judged reasonable they must, at a minimum, provide the company with a reasonable opportunity to earn a return that meets three standards:

a. Capital Attraction
b. Financial Integrity
c. Comparable Earnings

Each of these standards must be met on a forward-looking basis when setting regulated rates, regardless of the ratemaking method used now, or in the past. [Sections II. A, B and C.]

3) Rates based on cost-of-service establish the floor for reasonable rates according to the standards for a reasonable return. [Sections II. E and F.]

4) Assuming that it is able to obtain long-term contracts for its services, the storage operations of Intragaz face business risks that are somewhat higher than those of regulated gas transmission or storage companies, but still significantly greater than the business risks that are typical of Canadian utility companies. [Sections III and VII.]

5) With long-term contracts and the resulting ability to obtain a 50-50 debt-equity capital structure, Intragaz would have financial risks that are comparable to gas transmission and storage companies, but less than the financial risks of Canadian utility companies. When both business risks and deemed financial risks are considered together, the resulting overall risks of Intragaz would be slightly greater than the risks that are typical of companies in either of the proxy groups. [Sections III and VII.]

6) Based on the median result from a discounted cash flow (DCF) analysis applied to a proxy group of Canadian utility companies and supported by the results from a DCF analysis applied to U.S. natural gas pipeline and storage proxy companies, the cost of common equity for Intragaz is 11.75 percent. [Section VI.] The major components of this calculation are as follows:

Table 1
Calculation of Median Results

	Discounted Cash Flow (DCF)	
	Canadian Utility Proxy Group	U.S. Pipeline & Storage Proxy Group
Dividend Yield	4.08%	6.70%
Dividend Growth Adj. Factor	0.14%	0.13%
Expected Growth Rate	7.10%	4.00%
Flotation Cost Adj.	0.45%	0.43%
Return on Equity - DCF	**11.78%**	**11.26%**
Recommendation	**11.75%**	

7) The overall rate of return required for Intragaz' operations is 8.75 percent with a 50-50 deemed debt-equity ratio, a 5.75 percent cost of debt, and a required rate of return on common equity of 11.75 percent.

Q.7 What is the basis for the overall rate of return that Intragaz is requesting in this proceeding?

A. As shown in Table 2 below, based on an estimate of the capital structure that Intragaz could reasonably achieve if it obtains long-term contracts with its customer, Intragaz is requesting an overall rate of return of 8.75 percent. Because it is unlikely that a company like Intragaz could borrow debt for a period longer than the term of the contract(s) it has with its customer, the reasonable capital structure for Intragaz depends on the form and length of its contracts with its only customer, Gaz Métro.

Table 2: Intragaz Cost of Capital

Source	Capital Ratio	Cost	Overall Rate of Return
Long-Term Debt	50.00%	5.75%	2.88%
Common Equity	50.00%	11.75%	5.88%
Total	100.00%		**8.75%**

As my testimony discusses, an overall allowed rate of return of 8.75 percent, with an 11.75 percent return on common equity, represents a reasonable estimate of the cost of capital for Intragaz at this time.

C. Background Information

Q.8 Please describe the ownership and operations of Intragaz.

A. Intragaz, is a limited partnership between Gaz Métro and GDF Québec Inc. and is principally a developer and operator of underground natural gas storage facilities.

Intragaz operates two natural gas underground storage sites in Quebec, at Saint-Flavien and Pointe-du-Lac. The Saint-Flavien reservoir is located in a geological zone that is covered by nonporous carbonate, which serves as cap rock. The Saint-Flavien site principally provides seasonal storage service. The Pointe-du-Lac reservoir is a depleted gas reservoir located approximately 100 km northeast of Montreal. The storage facility is primarily used by Gaz Métro for peak shaving. Both storage facilities are connected to the TQM Pipeline. The capacity statistics for each storage site are depicted in the following table.

Table 3: Intragaz Storage Capacity[1]

	Saint-Flavien		**Pointe-du-Lac**	
Working Capacity	120,000 10^3m^3	4.2 Bcf	22,700 10^3m^3	0.8 Bcf
Max. withdrawal rate	1,930 $10^3m^3/d$	68.2 MMcfd	1,200 $10^3m^3/d$	42.4 MMcfd
Max. injection rate	900 $10^3m^3/d$	31.9 MMcfd	2,400 $10^3m^3/d$	84.8 MMcfd
Rate Base		$93.0 MM		$15.5 MM

II. RELEVANT REGULATORY PRINCIPLES

A. Criteria for a Fair Rate of Return

Q.9 Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

[1] Intragaz Limited Partnership (2009). *Our Activities*. Retrieved April 1, 2012, from Intragaz Limited Partnership: http://www.intragaz.com/en/activities_sites.html. The Rate Base numbers come from Intragaz-1, Document 3.

A. The principles surrounding the concept of a "fair return" were first established by the Supreme Court of Canada in the *Northwestern Utilities v. City of Edmonton* (1929) ("Northwestern") case, where the Supreme court established guidance regarding the level of the allowed rate of return that will meet the legal requirements of a fair return. The Court found:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[2]

Further, in the *British Columbia Electric Railway Co. LTD.* decision, the Supreme Court of Canada clarified that the duties of the regulator must balance the interests of the public while ensuring a fair return on rate base for the regulated utility. Specifically, the Court stated:

> The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. [3]

It is well understood in Canada that though a fair return is unlikely to cause hardship for a consumer, if it were to cause such hardship, the legal remedy should not involve setting a return below the level in which all three criteria of the fair return standard are met. This important distinction was affirmed by the Canadian Federal

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[2] *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186.

[3] *British Columbia Electric Railway Co. v. Public Utilities Commission,* [1960] S.C.R. 837, pages 855 and 856

Court of Appeal in 2004, in *TransCanada PipeLines,*[4] where it confirmed that the fair return need not be modified out of deference to its impact upon customers.

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

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

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

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

With passage of time in both Canada and the U.S., the fair return standard has been interpreted many times. The National Energy Board ("NEB") summarized its

[4] *TransCanada PipeLines v. Canada National Energy Board,* 2004 F.C.A. 149

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]

Q.10 Does the Régie embrace the same legal standards for the application of the fair return standard as those put forth by the NEB and those that have been established through Canadian and U.S. common law?

A. Yes. The same standards apply. The Régie recognizes the three primary criteria of the fair return standard (the comparability standard, financial integrity standard, and the capital attraction standard) and has indicated that they should be used as a guide in exercising its role with respect to fixing a reasonable rate of return.[6] In addition, the Régie has indicated that its duty to determine a reasonable rate of return and the method which it uses is at its discretion.[7] The Régie has also recognized that, like operating costs, the return allowed to the shareholder is one of the elements of the

[5] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, p. 17.
[6] Régie de l'énergie, D-2009-156, Décision, Gaz Métro, (December 7, 2009), at 189.
[7] Ibid. at 195.

regulated company's cost of service. The allowed return must, under the official Act[8] governing utility regulation, ensure that there are sufficient revenues to cover all of the costs.[9] The Régie also notes that the three required criteria make no mention of the user's ability to pay. As such, the Régie holds that "the users' ability to pay does not come into play on the quantum of a reasonable return for the shareholder." Instead, a balance is struck in protecting consumers' interests, by requiring that the rate allowed must not be excessive while being at least sufficient to provide a reasonable return.[10]

Q.11 What constraints do the fair return standards place on regulated rates?

A. When a regulator sets rates it must meet these standards. The fundamental principle is that a regulator may employ any method for setting rates, but the result reached must allow the regulated company a reasonable opportunity to recover its costs and meet the three standards required for a reasonable rate of return. The lowest possible rates that meet these three standards are rates based on the cost of service of the regulated firm. Consequently, although regulators often have wide latitude and flexibility in setting rates that are just and reasonable, the cost of service is the floor below which rates set by a regulator are not just and reasonable.

B. Stand-Alone Principle

Q.12 What is the stand-alone principle in regulation?

A. The stand-alone principle is the concept that regulated rates and the allowed rate of return should be set at a level that reflects the risks and investment characteristics of

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8 R.S.Q., chapter R-6.01, An Act Respecting The Régie de l'énergie which authorizes the Régie to set rates for regulated energy utilities in Québec.

9 Régie de l'énergie, D-2009-156, Décision, Gaz Métro, (December 7, 2009), at 192.

10 Ibid, at 193.

the regulated entity alone, as if it has no affiliates. This principle was described by the Alberta Energy and Utilities Board as follows:

> "This first application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. Using the stand-alone principle in this case, a utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged. This application of the principle ensures that the revenue requirement of regulated utility operations is not influenced up or down by the operations of a parent or sister company. Thus the cost (or revenue requirement) of providing utility service reflects only the expenses, capital costs, risks and required returns associated with the provision of the regulated service."[11]

This principle is applied widely throughout North America. For example:

> "The [National Energy] Board agrees with TransCanada that the stand-alone principle is a fundamental concept of utility regulation and a concept that it should continue to apply regulating TransCanada's Mainline."[12]

Similarly, the Ontario Energy Board has recognized that:

> "A longstanding regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the standalone principle."[13]

Q.13 What are the practical effects of the stand-alone principle?

A. In setting an appropriate capital structure, an allowed rate of return on common equity, and the cost of debt, a regulator should consider only the operations of the regulated company. If a parent company has greater risks, or lesser risks, than the regulated company, that fact should not affect the allowed rate of return. Similarly, the risks and financial positions of the parent, affiliates, or subsidiaries of the regulated company should not be considered in setting rates for a regulated company.

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[11] EUB Decision 2001-92, December 12, 2001, pp. 24-25
[12] NEB, Reasons for Decision, RH-R-1-2002 (February 2003), p. 26
[13] OEB RP-2002-0158 (January 16, 2004), paragraphe 124

Proper application of the stand-alone principle is essential for meeting the three standards required for a minimum reasonable allowed rate of return. For example, a capital structure with a deemed debt ratio that exceeds the amount that the regulated company can reasonably and prudently borrow on a stand-alone basis would not maintain financial integrity or allow the regulated company to attract capital on reasonable terms.

Similarly, the standards for a reasonable rate of return and the stand-alone principle would be violated if the regulator were to assume that the owners of a regulated company will provide uncompensated loan guarantees in order to increase the amount of debt, or to reduce the cost of debt, for the regulated company. When owners guarantee a loan for a regulated company the effect on risk is the same as if the regulated company has a higher equity ratio, because the owners who provide the guarantee have more "equity" at risk than the funds that they have invested directly in the company. Moreover, when an owner guarantees the debt of one of its investments or subsidiaries, the loan guarantee reduces the ability of the owner to borrow money for other operations and investments. As a result, debt that carries a loan guarantee has an economic cost that consists of two components: (i) the direct interest cost of the debt, plus (ii) the cost of the loan guarantee. When this second component – the cost of the loan guarantee – is considered, the true cost of guaranteed debt is essentially the same as the cost of common equity that is invested directly in the stand-alone regulated company. Thus, the regulated rates should be sufficient to meet the three standards of a reasonable rate of return without recourse, or reference, to the balance sheet or credit standing of affiliates. Otherwise, rates would not be just and reasonable.

Another common application of the stand-alone principle occurs when the allowed rate of return on common equity is set based on analyses of the returns required by a proxy group of companies with similar risks. Many regulated companies are owned by large, diversified holding companies, but the cost of capital for any particular subsidiary of a holding company generally is determined by estimating the costs of capital of other companies with risks that are as similar as possible to those of the regulated company. Thus, electric companies generally are used to estimate the cost of capital for electric companies, gas distribution companies are used to estimate the cost of capital for gas distribution companies, and gas pipeline and storage companies are used to estimate the cost of capital for gas pipeline and storage companies. The important point is that regulators purposely attempt to find the cost of capital for the stand-alone subsidiary, and not for the diversified holding company.

C. Prohibition Against Retroactive Ratemaking

Q.14 What is the prohibition against retroactive ratemaking?

A. It is a fundamental regulatory principle that rates should be set on a forward-looking basis and that current rates generally should not reflect past under-recovery or over-recovery of cost. There are certain exceptions to this principle such as when a company is allowed to set up deferral accounts and true-up mechanisms, but those mechanisms generally are adopted before rates go into effect and are implemented on a forward-looking basis. However, in the absence of such mechanisms, the general principle is that current customers should not be required to make up for inadequate returns earned by the regulated firm in the past, nor are current customers entitled to refunds of past earnings that may have exceeded the cost of capital. Whereas a formal method of deferred accounts and true-up mechanisms treats customers and regulated companies equally, the same cannot be said of retroactive ratemaking that is applied on an ad hoc basis. There is a good reason for the prohibition against retroactive ratemaking. When a regulator is allowed to apply ad hoc retroactive ratemaking there is the danger that it will apply the retroactive adjustments in an asymmetric way that is unfair and unreasonable because a regulator may decide to favor either customers or the regulated company.

A particularly extreme example of asymmetric retroactive ratemaking would occur if a regulator were to allow less than a reasonable rate of return at this time, specifically because it believes that the company earned more than its bare minimum cost of capital during some period in the past. The earnings in past years are the compensation that investors received for taking risks during those years, and there is no economic justification for setting a less-than-reasonable return for future rates in order to obtain a "refund" of past earnings.

The insurance industry provides a good example of this form of backward-looking determination of the rate of return to be included in future rates. For example, suppose a man pays a $500 premium to insure his car against the risk of an accident for an upcoming year. However, at the end of the year he then asks the insurance company to refund his premium because he did not have a car accident during the year. Of course the insurance company would refuse to pay a refund because the insurance company has already taken the risk that there could be an accident during that year. The fact that an accident did not occur does not mean that the risk did not exist. Nor does it mean that there was no cost associated with the risk.

In the case of a regulated company, a reasonable rate of return must be adequate to attract new capital and compensate for future risks on a forward-looking basis. Thus, if a regulator attempts to obtain a "refund" of past earnings by establishing a rate of return that is less than reasonable, that return will be insufficient to meet the capital attraction or comparable earnings standards, and it may not meet the financial integrity standard. In those circumstances, the resulting prospective rates would not be considered just and reasonable.

D. Public Policy Reasons to Allow a Reasonable Return

Q.15 How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards that are used to determine the minimum allowable fair rate of return for investors should apply. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company maintains its financial integrity and can attract capital so that the regulated services will be available in a quantity and quality that satisfies the needs of consumers and the public. There are countless examples of governments that attempted to protect consumers by setting regulated prices on important products so low that the products became scarce or of unsatisfactory quality. Such policies ultimately cause more harm than benefit for consumers. Effective regulation attempts to set rates and expected returns at a level that attracts capital sufficient to ensure that consumers will not experience service disruptions or poor quality service.

Consequently, there are good public policy reasons to set rates and the allowed return at a level sufficient to encourage continued replacement and maintenance, as well as needed expansions and new services. Thus, the consumer and public interest lies in establishing a return that will readily attract capital without being excessive.

Q.16 Is the Fair Return principle important for the overall well-being of the economy?

A. Yes. Investors in the economy have an obvious interest in maintaining the value of their investment. If they do not expect a government to allow them a reasonable opportunity to earn a fair return, they will not invest their capital in that jurisdiction. Consequently, there is a very pragmatic reason why successful economies tend to be those that protect the rights of investors against government policies that would unjustifiably diminish the value of their investments. The perception of government fairness affects investment in both regulated and unregulated industries and thereby affects the overall prosperity and economic well-being of the citizens. Thus, in addition to ensuring adequate, reliable service in the regulated industry, there is a broader public interest that is promoted by the Fair Return principle.

E. Cost of Service Ensures that Alternative Rates Remain Reasonable

Q.17 Why are cost-based rates considered to be a baseline for determining whether regulated rates are just and reasonable?

A. Cost-of-service is the baseline standard that is used to determine whether regulated rates are just and reasonable. This principle is discussed in the textbook by Bonbright, Danielsen and Kamerschen:

> "… one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of costs of service …"[14]
>
> *   *   *   *
>
> "In the regulation of private utility companies, and even in the ratemaking practices of publicly owned plants, the determination of general rate levels is likely to take precedence over the determination of specific rate schedules; and there the most directly pertinent costs are the total costs, including the overhead costs. In other words, the cost principle is taken to mean that rates as a whole should cover costs as a whole."[15]

Although regulators may adopt other non-cost-based ratemaking methods for a variety of public policy reasons, cost-of-service represents a legal floor under which regulated rates generally are not considered to be just and reasonable. It is not unusual for regulatory commissions to adopt alternative, non-cost-based rates, and at the same time adopt measures to ensure that the cost of service will be used if the alternative rates became insufficient to recover costs. One example of this is the method used in regulating U.S. oil pipelines. Similarly, "re-set" mechanisms are common in performance-based ratemaking schemes to ensure that rates do not deviate too far from costs.

1. U.S. Oil Pipeline Regulation

Q.18 How does the Federal Energy Regulatory Commission set rates for U.S. oil pipelines?

A. The regulatory structure established by the Energy Policy Act of 1992 and FERC's Order No. 561 provides a good example of the principle that cost-based regulated rates are required when non-cost-based approaches fail to yield just and reasonable rates. Order No. 561 allows a pipeline to change its rates each year according to an index that

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[14] Bonbright, Danielsen and Kamerschen, *Principles of Public Utility Rates,* Public Utilities Reports, Inc. (Arlington, VA: 1988), p. 109.

[15] *Ibid*., p. 116.

is based on the general inflation rate in the economy. As long as a pipeline's rate increases remain less than the cumulative changes in the index, the pipeline's rates are deemed to be just and reasonable and FERC will not base the rates on the cost of service.[16]

Q.19 Can an oil pipeline elect to use cost-of-service in setting its rates if the indexed rate is too low to allow it to recover its costs?

A. Yes. A pipeline is permitted to apply for a cost-of-service rate if its costs are higher than the ceiling established by the indexed rate. In addition, customers may make a complaint if they believe that the indexed rate is too far in excess of costs. FERC Order No. 561-A explained that:

> … the regulations also provide procedures for both pipelines and their customers to show that the applicable ceilings would not ensure just and reasonable rates. As explained in detail in the final rule, and elsewhere in this order, §342.4 provides that the pipeline may rebut the presumption in the regulation that the above-ceiling rate is unjust and unreasonable and that rates above the ceiling are justified. The pipeline has the burden of proof to show that the applicable ceilings are too low to allow recoupment of prudently incurred costs, in respect to both proposed and existing rates, except for those rates deemed just and reasonable under section 1803 of the Act of 1992. Section 343.2(c)(1) provides similar protection for customers, by providing for challenges to proposed and existing rates that are within applicable indexed ceilings, but are nonetheless so substantially in excess of actual costs as to be unjust and unreasonable.[17]

Q.20 What conclusions can you draw from the U.S. Oil Pipeline ratemaking method?

A. Although a non-cost-based indexing approach was implemented for setting U.S. oil pipeline rates, the regulatory structure specifically provides an option to use cost-based rates if the indexed rates are too low to allow the pipeline to recover its cost of service.

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[16] "Generally, the initial rate [for a new pipeline] will be established by a cost-of-service showing. However, a pipeline may file an initial rate based upon the agreement of at least one non-affiliated shipper. The Commission will not require a cost-of-service justification for such an agreed-upon rate. An initial rate established by agreement may be protested, in which case the pipeline will be required to justify the rate based on a cost-of-service showing." FERC Order No. 561, October 22, 1993, Docket No. RM93-11-000, p. 30,948

[17] FERC Order No. 561-A, July 28, 1994, Docket No. RM93-11-001, p. 31,101

By generally providing the pipeline with the option of using the higher of cost-based or indexed rates the method ensures that the regulated rate will meet the legal standards required for a minimum reasonable rate of return.

2. Performance-Based Rates

Q.21 Is it common for regulators to approve non-traditional performance-based rate programs that allow earnings greater than the cost of capital, but that also provide rate adjustments if the company is unable to earn a reasonable rate of return?

A. Yes. Many regulatory Commissions have approved performance-based rate programs that are designed to provide an additional incentive by allowing the regulated company to earn a higher rate of return if it is able to achieve greater efficiencies. However, it is common for these programs to have a mechanism that re-adjusts the rates when the earned rate of return falls outside of a reasonable range.

F. Application of Ratemaking Principles to Intragaz

Q.22 Would you briefly describe the history of Intragaz rate regulation?

A. Development of the first of the Intragaz storage fields was proposed by Gaz Métro in 1988, but the Régie discouraged that proposal because of the high risk of developing a storage field (Decision G-475 dated June 13, 1988). The Régie was concerned that consumers could be required to pay for a failed facility if Gaz Métro attempted to develop the storage field as part of its regulated distribution system rate base. As ordered by the Régie, a separate company subsequently was used to develop the storage site so that all of the development risk would be borne by investors, and consumers would not bear any of the high development risks.

In its Order D-89-21 dated July 21, 1989, the Régie recognized that "no investor had shown interest in realizing the project based on rates approved by the Régie in Order G-485." Those rates, based on cost of service estimates, even included an explicit risk premium over the then-allowed rate of return for Gaz Métro. The storage-specific risk premium was 5 percent in year 1 and was designed to decline by one percent each year until it was zero in year 6 (Decision G-475, page 20). Ultimately, however, this explicit storage risk premium proved to be insufficient to induce any investors to take on the risks of developing storage.

As an alternative incentive for the promoters to develop the storage facility, the Régie subsequently stated that the Company would be allowed to charge a regulated rate that exceeded its cost of service. It was estimated at the time that this incentive represented approximately $3.8 million per year over the rates previously approved in Order-485 (R-3166-89, transcripts of July 10, 1989, page 109, testimony of Mr. Bernard Otis). The incentive rate was to be set equal to the avoided cost of alternative arrangements that Gaz Métro might require in order to meet the needs of its customers. The "Avoided Cost" rate originally was intended to provide a premium over cost as an incentive, while also providing a regulated rate ceiling to protect consumers from excessive rates, thus ensuring that the rate fell within a zone of reasonableness.

As a result of this incentive rate structure, Intragaz signed a contract to provide storage services to Gaz Métro at a regulated rate and invested $17.5 million to develop the Pointe-du-Lac site prior to beginning operations in 1991. When it came time to develop the Saint-Flavien site in 1993, the same logic was applied by the Régie in again approving Avoided Cost rates (Order D-94-06).

The Avoided Cost method provided two forms of incentives. First, because the Avoided Cost rate was greater than the cost-based rate, it provided an incentive for investors to take the risks to develop the storage fields in Québec. Second, because the Avoided Cost rate was unrelated to costs, Intragaz had an incentive to minimize the operating costs and investments required to provide the level of service it offered.

Q.23 Is the Avoided Cost rate an unregulated rate?

A. No. The Avoided Cost rate was established by the Régie and changed from time to time through the years based on evidence concerning Gaz Métro's avoided costs. This form of regulated ratemaking is sometimes used in circumstances when the regulator or government wishes to encourage certain economic activities that are deemed to be in the public interest.

For example, in the U.S. there was a period of time beginning in the late-1970's when electric utilities were required to purchase electricity from industrial facilities that installed cogeneration equipment, and to pay an Avoided Cost rate to the cogenerator. Because the Avoided Cost rate was equal to the marginal cost of the most costly source of generation, the rate paid to the generator was generally considerably above the utility's average cost of generation. This relatively high Avoided Cost rate provided an incentive for the market to install additional cogeneration equipment that improved the efficiency of energy usage.

Rates based on avoided costs also are advocated in some instances as an alternative ratemaking method that provides greater incentives for regulated companies to operate efficiently. Because the Avoided Cost rate is independent of the costs of the regulated company, the regulated company is not required to pass through cost savings or efficiency improvements to ratepayers during the term of the rate.

Q.24 Is the Avoided Cost rate the same as a market-based rate?

A. No. Avoided Cost rates are set by the regulator and use the costs of alternatives as a yardstick, or cap, on the allowable rates. When Avoided Cost rates are adopted by the regulator there usually is a determination that such rates are just and reasonable because they promote an explicit public interest goal while also protecting customers from excessive rates. As long as the regulator retains and exercises its authority to set just and reasonable rates, the regulator is required to set rates that are at least sufficient to allow the regulated firm a reasonable opportunity to recover its costs and earn the rate of return required by the market. However the regulator can allow the company to charge more than its cost of service when it is in the public interest to do so. This concept is known as the "zone of reasonableness" of just and reasonable rates.

In contrast, a "market-based" rate does not involve the regulator in the ratemaking process. Instead, an unregulated company – or a regulated firm with market-based rates – may set its rates at the highest level that the market will bear. Regulators sometimes allow regulated companies to charge market-based rates when it is determined that the market is sufficiently competitive that it is reasonable to rely on competition to hold rates down to a reasonable level. This means that the regulator exercises forbearance and refrains from intervening in the agreements negotiated between buyers and sellers.

The obvious distinction between "Avoided-Cost" and "market-based" rates is that when Avoided-Cost rates are adopted the regulator retains, and actively exercises, its power to prescribe rates. The Régie has made it clear that it is actively exercising its power to prescribe rates for Intragaz and that it is not allowing market-based rates:

> "In the absence of effective competition in the gas storage market in Québec, the Régie determines that the non-disclosure of Intragaz' rates is not justified. The Régie believes that it is indeed in the public interest that it continues to set Intragaz' rates rather than rely on market forces and that the review of the rates be done in a public process."[18]

As discussed earlier, there is a well-established principle in Canada and the U.S. that when a regulator prescribes rates, regardless of the method employed, the regulator must afford a regulated company an opportunity to earn a fair and reasonable rate of return on its investment; and the fair and reasonable rate of return is defined by three standards: comparable earnings, financial integrity, and capital attraction. Thus, a regulator generally is not permitted to prescribe rates that prevent a company from having a reasonable opportunity to recover its prudently-incurred costs.

Q.25 What are the established regulatory principles regarding prudently-incurred costs?

A. Regulators may deny an opportunity to recover costs that are "imprudent," or costs of facilities that are not "used and useful" in serving the public. Neither of these exceptions is relevant for Intragaz' circumstances.

[18] Régie de l'énergie, Decision D-2002-56, March 8, 2002, p. 18 (Translation).

The test of prudence is applied by examining the circumstances that were known at the time that the investments were made, or the costs were expended. Moreover, there is a well-recognized principle that management is presumed to act prudently. For example, "Unless there is direct evidence of mismanagement, regulatory agencies will presume that management has properly performed its duties."[19] More specifically, "a legal presumption that utility management has acted prudently surrounds their investment decisions."[20] Finally, "an allegation of imprudence must be supported by evidence that creates a serious doubt regarding the prudence of the investment."[21] Most of the costs of Intragaz' facilities were expended many years ago and no one has suggested that the cost of these facilities were incurred imprudently. Indeed, Decision D-2011-140 states that "The Régie does not dispute Intragaz' presumption that the investment decisions made in the past were prudent."[22] Consequently, the prudency of Intragaz' investments must be presumed.

Similarly, it is clear that the Intragaz facilities are used and useful in serving the public because Gaz Métro relies on these facilities, in conjunction with its own LNG facility, as its only in-franchise source of supply security. In addition, it is my understanding that Intragaz will be filing as part of this proceeding an independent review of the usefulness of its individual assets in response to the Régie's conclusion in Decision D-2011-140 that "the evidence on record is insufficient to allow the Régie to give an opinion on the useful nature of these investments."[23]

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[19] Leonard Saul Goodman, *The Process of Ratemaking*, p. 840.
[20] Ibid, at p. 860.
[21] Ibid, at p. 861.
[22] Decision D-2011-140, Docket R-3753-2011, September 16, 2011, paragraph 46 (Translation).
[23] Ibid, at paragraph 46 (Translation).

Q.26 What do these regulatory principles indicate in respect to the use of Avoided Cost to set rates for Intragaz?

A. The legislature has determined that Intragaz is regulated and the Régie is bound by the Act.[24] As the Régie has observed in its D-2011-140 decision:

> [52] By virtue of the last sub-paragraph in Article 49 of the Act, the Régie may use any other method it deems appropriate when it sets a storage rate. However, the discretion that the Régie has in the choice of methods does not relieve it of its obligation to set rates and other conditions that are just and reasonable from the point of view of the customers, the regulated company and the public interest.

The regulatory principles discussed above indicate that just and reasonable rates require the regulator to set rates that are at least sufficient for Intragaz to recover its costs, including a reasonable rate of return. Thus, although the regulator has latitude to use many alternative ratemaking methods, including Avoided-Cost rates, its latitude is not unlimited and the cost-based rates represent a floor for any just and reasonable rates that are set by the Régie.

III. NATURAL GAS STORAGE OPERATIONS AND RISKS

Q.27 What is the function and economic rationale for underground natural gas storage?

A. Underground natural gas storage facilities serve numerous functions. Natural gas storage located downstream and close to market is valuable as a substitute for additional firm capacity on pipelines and also provides an important element of physical supply security by ensuring reliability during daily demand spikes and potential disruptions of upstream supply networks. Market-area storage also may be integrated with the facilities of a local distribution facility by providing an economical

[24] R.S.Q., chapter R-6.01, An Act Respecting The Régie de l'énergie which authorizes the Régie to set rates for regulated energy utilities in Québec, section 1.

means of maintaining service pressures and balancing in specific locations on a local distribution company's (LDC's) system.

Upstream natural gas storage is used to manage imbalances between the rates at which gas is produced and consumed. Natural gas storage also can be used as a hedge against seasonal and daily commodity price volatility. The North American natural gas market is a winter-peaking market, generally exhibiting higher prices during winter months due to heating load and lower prices in the summer months. By injecting gas during the summer months for withdrawal in the winter when commodity prices are higher, distribution companies can reduce their commodity costs. With the increased use of natural gas to generate electricity, daily price volatility has also increased during summer months. Storage allows distribution companies to meet these summer demand peaks with less expensive gas that was injected during shoulder and summer months.

Q.28 Please describe the facility risks associated with underground storage?

A. Developers of underground storage facilities face a number of construction risks. As the FERC has observed, "There is an inherent uncertainty regarding the performance of an underground reservoir; its actual boundaries depend on characteristics that can generally be confirmed only after the facility has commenced operation".[25] In other words, all underground storage developments face the prospect that the facility will fail to hold gas. In some cases, storage projects progress to an advanced stage where all required infrastructure is in place and virtually all project-related capital has been expended, before it can be determined

[25] *Williston Basin Interstate Pipeline Company*, 127 FERC ¶ 61,045.

that the reservoir fails to demonstrate structural integrity. An example of this type of facility risk can be seen in the development of the Liberty Gas Storage Project. On December 8th, 2005, FERC authorized Liberty Gas Storage, LLC to construct and operate two salt dome natural gas storage caverns and related facilities in Calcasieu Parish, Louisiana. Liberty developed the two caverns and constructed compressors, pipelines and other infrastructure necessary to operate the storage project. However, just before Liberty was to place the project in service, both caverns failed integrity tests. Despite the company's best efforts to identify and resolve the integrity issues, in December 2009, Liberty filed to abandon the storage project. Upon receiving FERC approval, the project assets were converted to other use, transferred to third parties or abandoned in place.[26] Liberty's ultimate parent company, Sempra Energy, recorded an asset write-off of $64 million USD related to the project's storage assets in 2009.[27]

Q.29 What other facility risk does an underground storage developer face?

A. The uncertainty regarding the performance of underground storage developments can also lead to substantial construction cost overruns which may prevent the facility from ever being placed in service. In September 1994, Avoca Natural Gas Storage received Commission approval to construct and operate a 5 Bcf storage facility in salt caverns located near Avoca, New York. Upon commencing construction, however, the Avoca project was fraught with cost overruns and construction delays. Avoca originally intended to inject the brine from the caverns into deep wells for disposal. The disposal wells were drilled, but due to low acceptance rates in these

[26] *Liberty Gas Storage, LLC*, 133 FERC ¶ 62,033.
[27] Sempra Energy 2009 Form 10-K.

wells, this course had to be abandoned. Avoca filed in February 1997 to alternatively construct a 45-mile brine pipeline from the storage facility to a nearby salt processing plant, but soon concluded that the brine pipeline was also not cost-effective. In July 1997, Avoca filed for Chapter 11 Bankruptcy as the original backers of the project withdrew their support. In its bankruptcy petition, Avoca said it had assets of $1 million to $ 10 million and liabilities of $ 10 million to $ 99 million.[28] Ultimately, Avoca filed to abandon its storage project via the sale of its assets to another party.[29]

Q.30 Does all facility risk pertain to the construction period of an underground storage project?

A. No. Once operational, underground storage projects also face the danger of a loss of structural integrity which can lead to gas migration. In some cases, gas migration can be managed, either through the acquisition of expanded property rights or adjustments to compression, but in other cases migration can render the facility economically unviable. An example of gas migration resulting in abandonment can be found in Transcontinental Gas Pipe Line Corporation's ("Transco") Hester Storage Field. The Hester Storage Field was originally a gas producing field that was converted to a gas storage field in 1971. Transco acquired the Hester Storage Field, located in St. James Parish, Louisiana in 1977. In the 1980s, Transco's storage inventory calculations revealed gas losses from the field. An engineering and geologic study completed in 1990 concluded that 3.4 Bcf of gas had been lost between 1982 and 1989. Transco made numerous efforts to identify the cause of the gas migration, including the construction of observation wells and lowering the operating pressure, but the gas losses continued. In 2004, after a second consultant

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[28] Platts Inside FERC, "Brine-Disposal Problems Forced Avoca into Bankruptcy", August 4, 1997.
[29] *Avoca Natural Gas Storage*, 88 FERC ¶ 62,245.

study failed to identify the cause of the migration, Transco ceased operations at the Hester Storage Field. The Commission ultimately approved the abandonment of the Hester Storage Field in October 2008. The total cost to abandon the project was estimated to be $8.95 million.[30] According to Transco's final inventory calculations, cumulative gas losses from the field totaled 7.3 Bcf.[31]

Q.31 In the past, has the Régie recognized the unusually high facility risks of storage operations?

A. Yes. With respect to the first proposal to develop the Pointe-du-Lac site, the Régie observed:

> The flow of fluids in two phases in a porous environment with relatively unknown characteristics presents a problem which is entirely different from the flow of a dry gas in a steel pipeline.
>
> Therefore, the Régie considers that this project is distinct from the various extensions of the system that it has authorized to date, due to the higher level of risk associated with such an operation in the first phases of its development.[32]

As a result the Régie recommended that the site be developed by an independent company and be given a large risk premium in its allowed rate of return during the first five years of operation *"… so that shareholders will agree to assume the additional risks associated with this project."*[33]

Q.32 How does the strategic nature of the Company's storage facilities affect their value?

A. The Company's two storage facilities are the only underground storage capacity available in the province of Québec and, in conjunction with Gaz Métro's LNG facility, the only in-franchise storage in Gaz Métro's supply portfolio. Consequently,

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[30] Foster Natural Gas Report, "Transco Decides to Close Down One of Its Big Three Storage Service Facilities", Report #2693, May 9, 2008.
[31] *Transcontinental Gas Pipe Line Corp.*, 125 FERC ¶ 62,003.
[32] Decision G-475 (Translation), June 13, 1988, p 18.
[33] *Ibid., p. 20.*

these two Intragaz facilities provide a unique value to Gaz Métro in terms of load balancing and supply security. The value to Gaz Métro of in-franchise storage capacity is augmented by the fact that Gaz Métro's service territory lies at the extreme end of the market zone for TransCanada's Mainline pipeline, exposing the utility to greater risk of supply disruptions. Intragaz' strategic advantages help to mitigate the market risk faced by the Company.

Q.33 Has the Régie recognized the strategic advantages of Intragaz?

A. Yes. In approving rates for the Pointe-du-Lac facility, the Régie made the following statement:

> The Régie will later decide on the legal aspect but wishes to indicate immediately that it deems the Pointe-du-Lac project necessary and in the public interest. Moreover, this project not only falls under Québec's current energy policy, but … it also meets a real need which continues to increase.[34]

Similarly, in approving the rate and terms for the Saint-Flavien facility, the Régie stated that:

> … the Régie believes that given its strategic importance for the distributor, the project involving the development and use of the Saint-Flavien reservoir is in the public interest and that there are grounds for encouraging its realization.
>
> The Régie is retaining the avoided costs method submitted by the co-applicants because for the moment, and in this specific case, … it is "the only method that has allowed the emergence of a promoter interested in entering into a contract to realize this project".
>
> The Régie nevertheless believes that approval of a pricing methodology in prior cases does not exempt the parties from the obligation to prove, in subsequent cases, the relevance and advantage of the methodology over other methods.[35]

[34] Decision D-89-21, July 21, 1989 (Translation), paragraph 21.
[35] Decision D-94-06, March 2, 1994 (Translation).

The Régie acknowledged the continued importance of these facilities earlier this year when it recognized *"(t)he advantage for Gaz Métro resulting from the fact that the Pointe-du-Lac site is located in the heart of the territory it serves.*"[36]

These decisions indicate that Intragaz is an important strategic asset for Gaz Métro, and the purpose of the Avoided Cost method was to encourage the construction of these high risk facilities.

Q.34 How would the Company's risks be mitigated by its rate and contract proposal?

A. The 10-year contract with Gaz Métro that Intragaz is proposing in this proceeding, in conjunction with a corresponding 10-year rate horizon, would help to mitigate risks. However, to the extent that its contract(s) with Gaz Métro has a term substantially less than the remaining depreciable life of the Intragaz facilities, Intragaz would retain significant risks.

Moreover, in connection with the 10-year contract proposed in this proceeding, the Company is proposing projected cost-of-service rates that would decline annually according to a fixed schedule for a period of ten years. The proposed rates and 10-year contract would mitigate some of the risks associated with recovering costs adequate to support their operations and allow debt financing. However, Intragaz would still face the risk of unforeseen events such as revenue losses in the event of a force majeure service interruption during the term of the contract.

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[36] Decision D-2012-005, January 26, 2012 (Translation), paragraph 43.

Q.35 How do the risks of storage operations compare with those of a Local Distribution Company (LDC)?

A. Storage operations are considerably riskier than LDC operations. The technological and engineering risks of storage discussed earlier are notably higher than similar risks for LDCs. The Régie explicitly noted this higher risk when it denied Gaz Métro's original application to develop storage facilities as part of its regulated LDC rate base.[37]

In addition, LDCs typically operate under exclusive franchise agreements that effectively eliminate all, or most, of the risk of contract renewal or direct competition in their core markets. Unlike franchised LDCs, independent storage operators rely upon contracts with LDCs or marketers that can decide to not renew the contracts. These contrasting circumstances expose storage operations to substantially greater recontracting risk than LDC operations face. Although LDCs with exclusive franchises continue to face competition from alternative fuels such as electricity, oil and propane, storage operators – because they are part of the natural gas supply chain – face the same risks and competition from alternative fuels.

High recontracting and other business risks also make it more difficult for storage operators to access credit markets. A December 2008 report by Standard & Poor's noted that none of the storage projects rated by the agency at that time had an investment-grade rating ('BBB-' and above) and identified the ability to lock-in long-term storage contracts as a criteria to achieve an investment-grade rating.[38] The lower credit ratings issued to storage operations make it more difficult and costly to

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[37] Decision G-475 (Translation), June 13, 1988, p 18.

[38] Standard & Poor's, *U.S. Natural Gas Storage Owners Face Uncertainty As the Sector Copes With Volatile Prices And Demand*, December 23, 2008.

access credit markets. In contrast, LDCs are typically rated as solid investment grade due to their long-term franchise agreements and cost-of-service rates designed to produce reasonable returns.

Q.36 Does Intragaz face any risks that are high relative to those of other pipeline or storage companies?

A. Yes. The major risks for Intragaz relative to the proxy group that I describe in more detail later in my testimony include: 1) its reliance on a single customer, Gaz Métro; 2) contracts that are significantly shorter than the depreciable life of its assets; and, 3) its small size relative to the proxy companies. In addition, the technical risk of storage companies is much higher than for pipeline companies because of the uncertainties related to underground reservoirs.

IV. DETERMINATION OF THE REQUIRED RATE OF RETURN

Q.37 What sort of examination is necessary to ensure that the three criteria required by the fair return standard are satisfied in evaluating the reasonableness of a proposed return?

A. As discussed earlier, the three criteria are: (1) comparable earnings, (2) financial integrity, and (3) capital attraction. In my opinion, criterion (1) requires an examination of the returns that are actually earned in the primary financial markets by enterprises with corresponding risks. Legal criteria (2) and (3) generally will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. Criterion (2) suggests that the *overall* allowed rate of return, must also be sufficient to maintain a solid investment-grade bond rating. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk, there is a corresponding level of return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q.38 How is the cost of long-term debt determined?

A. For purposes of setting regulated rates, the actual, embedded costs of long-term debt generally are used in order to ensure that the company receives a return that is sufficient to pay the interest obligations that are attached to this source of capital. However, because Intragaz currently does not know how much debt it will have outstanding, or the cost of debt, at the time the new rates will go into effect in May 2013, a deemed capital structure consisting of 50 percent debt and 50 percent common equity, and an annual cost of debt of 5.75 percent have been estimated based on the rates quoted to Intragaz in a survey of financial institutions. That survey is described in the testimony of Intragaz witness M. Marois. Because of the uncertainties surrounding its eventual refinancing (the amount as well as the terms and conditions), my understanding is that Intragaz will be seeking permission as part of this proceeding to update its filing to reflect the actual debt cost once the refinancing is completed.

Q.39 How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity generally is to use the current cost of common equity, as inferred from studies of the secondary financial markets, in order to ensure that the return is adequate to attract common equity capital to the company. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital.

For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on the DCF analysis, based on two sets of proxy companies: one consisting of Canadian regulated utilities and another consisting of U.S. natural gas pipeline and storage companies. Because there are no publicly-traded, pure storage companies with sufficient data to conduct an analysis, the analysis also requires a comparison of the risk characteristics of the proxy companies with the risk of Intragaz in order to establish a reasonable return relative to the return required by the proxies. I have also conducted Risk Premium analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches is described later in this testimony.

Q.40 Have any other public utility commissions in Canada given primary weight to the DCF analysis?

A. Yes, the British Columbia Utilities Commission ("BCUC") has given weight to the DCF method in the past and recently adopted the DCF analysis as its primary method for determining ROE in a case involving Terasen Gas. For example, in 2006, the BCUC gave weight to both the Equity Risk Premium ("ERP") and DCF approaches when determining a fair rate of return.[39] Again in 2009, the BCUC considered DCF, ERP, and CAPM approaches, but found that the DCF and ERP are the most common approaches and determined "that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific."[40] Overall, the BCUC decided "that in determining a suitable ROE…it will give most weight to the DCF approach…"[41] For the DCF approach, the BCUC found that U.S. data can act as a proxy for Canadian data and rejected suggestions of analyst bias, noting that no allegations of upward bias have been leveled against utility analysts.

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[39] British Columbia Utilities Commission, In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, March 2, 2006, p. 1.
[40] British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure, December 16, 2009, p. 45.
[41] Ibid.

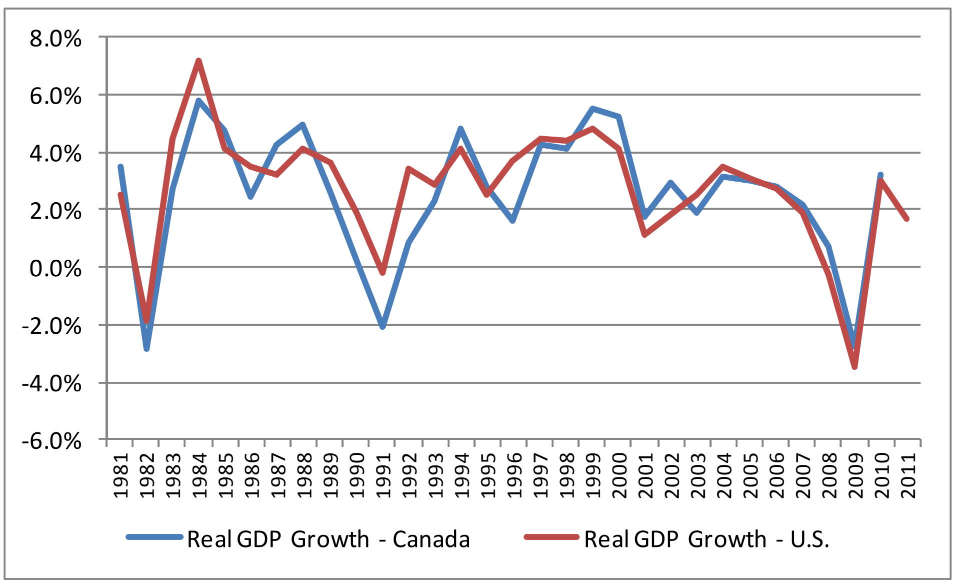
A. Interest Rates and the Economy

Q.41 What are the general economic factors that affect the cost of capital?

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Although the Canadian economy has been somewhat slow to recover from the global recession, domestic demand and personal spending are growing steadily. The U.S. economy has stabilized with renewed appetite for energy to fuel its commercial expansion prompting an increase in Canadian fuel exports and extractive energy production. The continued U.S. economic recovery is an important factor for the Canadian economic recovery and will undoubtedly be the driving influence. Positive signs of U.S. recovery may be observed in a declining unemployment rate, strong rebound of equity prices, narrowing credit spreads and easing concerns about the global economy. Nonetheless, a variety of concerns, such as rising fuel costs, a surge in inventories, and the impact of the Eurozone crisis on exports have dampened the optimism. Generally, the Canadian economy and U.S. economy move in tandem due to the very close trade relationship and more generally to the overall globalization of the world economy. Consensus forecasts indicate modest but steady real GDP growth and inflation for both North American economies.

In both countries, on average, real growth in the Gross Domestic Product ("GDP") has slowed over the last three decades. During the past 30 years, Canadian GDP averaged 2.6 percent annually, 2.4 percent for the past 20 years and 1.9 percent for the past 10 years. This compares with 2.7 percent, 2.5 percent for the past 20 years and 1.6 percent for the past 10 years, for the U.S., respectively. However, more recently, real GDP in Canada increased at an annual rate of 3.2 percent in 2010 and 2.5 percent in 2011, up from a dip in GDP in 2009 of negative 2.8 percent. This corresponds to an increase in real GDP in the U.S. of 3.0 percent in 2010, and 1.7 percent in 2011, up from a dip in GDP in 2009 of negative 3.5 percent. As Figure 1 illustrates, the Canadian and U.S. economy track each other very closely in real terms.

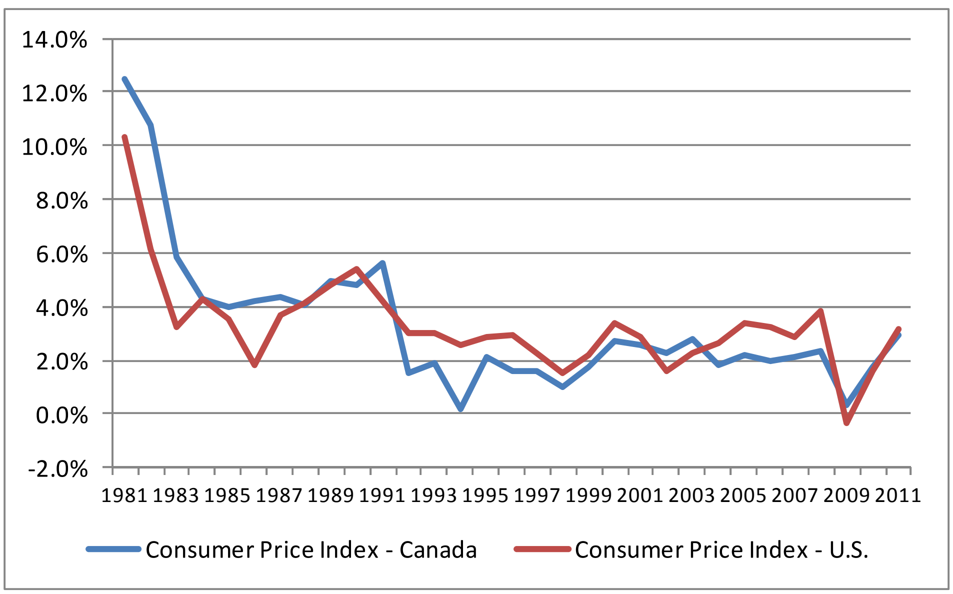
Figure 1: Real GDP Growth – Canada and the U.S.



As Pages 4 and 5 of Schedule 1 show, Canadian interest rates on longer-term, intermediate quality corporate bonds have declined since their height in the Fall of 2008 with recent yields on A-rated public utility bonds at approximately 4.08 percent and the yields on BBB-rated public utility bonds at approximately 4.18 percent. In the U.S., interest rates have experienced a similar decline with A-rated public utility bonds at approximately 4.40 percent and the yield on Baa-rated bonds at 5.11 percent. On the other hand, credit spreads in both countries have remained relatively constant in recent years after declining from the high levels experienced during the financial crisis.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index in Canada has increased at an average annual rate of 2.1 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in Canada, has increased at an average rate of 2.4 percent. This corresponds to increases in the U.S. of 2.5 percent and 2.3 percent, respectively.

Figure 2: CPI – Canada and the U.S.



According to *Consensus Economics* the Consumer Price Index year-over-year increase is forecasted to decline slightly in Canada to 1.8 percent in the 3rd quarter of 2012 before gradually climbing to 2.1 percent towards the end of 2013.[42] Individually, certain economic indicators show some improvement, yet the overall economy is only slowly showing signs of recovery.

[42] Consensus Forecasts, Consensus Economics, April 10, 2012 Survey, at 16.

B. Capital Structure

Q.42 What capital structure are you recommending for Intragaz?

A. Based on its discussions with lenders, Intragaz has found that it would be unable to issue any significant amount of debt without long-term contracts with its customer. However, it is anticipated that Intragaz would be able to issue debt that is paid down over 10 years if the proposed 10-year cost-based rate is approved and Intragaz is able to contract with Gaz Métro for that time period. Based on preliminary discussions with lenders, Intragaz is filing a deemed capital structure consisting of 50 percent common equity, and 50 percent long-term debt. This common equity ratio is consistent with the median of the equity ratios for gas transmission and storage companies shown on page 2 of Schedule 9.

Q.43 Has the Régie recognized Intragaz' need for long-term contracts in order to issue debt?

A. Yes. In its decision last year, the Régie made the following observation:

> The Régie is aware that Intragaz is a company whose operations are based on long-term assets and that, therefore, must support significant and sustained fixed expenses. It takes note of Intragaz's comments mentioning that it is the revenues generated by its contracts that can be given in guarantee to its lender. Ideally, this revenue flow would result from a long-term contract that ensures stability and predictability and thus an adequate capital structure. **It also takes note that the stability and predictability of revenues, as well as the length of the contract that will prevail with Gaz Métro will be key elements in reaching and maintaining an appropriate capital structure.**[43]

[43] Régie de l'énergie, Decision D-2011-140, Intragaz, September 16, 2011 (Translation), paragraph 60, emphasis added.

Q.44 How is the "Stand-Alone" principle relevant for setting a deemed capital structure for Intragaz?

A. In its decision D-2011-140, the Régie stated that:

> [61] However, the Régie is of the opinion that it is the responsibility of Intragaz' shareholders to find adequate financing and capital structure, according to the constraints and opportunities that the capital markets offer as well according to the company's earnings prospects. It is also the responsibility of Intragaz' shareholders to give certain guarantees if the lender's conditions do not satisfy its expectations regarding the amount of the loan, interest rate or capital reimbursement clauses.

If a regulator were to deem a debt ratio that the company could not achieve unless shareholders provided uncompensated loan guarantees to lenders, the resulting return allowance would be insufficient to attract capital on reasonable terms and would violate both the fair return standard and the Stand-Alone principle.

C. Cost of Debt

Q.45 What debt cost rate have you used for Intragaz?

A. Although Intragaz currently is in the process of refunding its outstanding long-term debt,[44] it plans to issue long-term debt based on the assumption that the Régie will approve cost based rates and that it will be able to obtain a contract of at least 10 years with its customer, Gaz Métro. Consequently, for purposes of this rate filing, Intragaz is filing a deemed cost of debt of 5.75 percent. This debt cost is based on the rates quoted to Intragaz in a survey of financial institutions. This rate is approximately 100 basis points higher than the average yield on Canadian Corporate bonds in recent months as shown on page 4 of Schedule 1. Consequently, it would be consistent with

[44] Intragaz must refund most of its current debt prior to the expiry of its contracts with Gaz Métro in April 2013. Only the portion guaranteed by the cushion gas can remain outstanding at the expiry of its contracts with Gaz Métro.

the higher risks that Intragaz faces. However, Intragaz plans to update its rate filing when it knows the actual debt costs.

D. Overview of ROE Cost of Equity Estimation

1. Discounted Cash Flow Model

Q.46 Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital using the DCF method, therefore, is a matter of calculating the current dividend yield and estimating the long-term, future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the constant growth DCF formula generally consists of the dividend per share of that company divided by the price per share, and utilizes readily available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q.47 What DCF formula do you use in this proceeding?

A. In this study I will use the following general form of the DCF model:

$$K = \frac{D\,(1 + .5g)}{P} + g \qquad (1)$$

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

I also have adjusted my calculated cost of capital for a required flotation cost adjustment.

2. CAPM Model

Q.48 Please describe the CAPM method of estimating the cost of common equity capital.

A. CAPM is an extension of the simple Equity Risk Premium model, where common equity investors are deemed to measure their required return based on a risk free rate of return plus compensation for the relative risk of a specific stock in relation to the broader market. This model may be expressed as:

$$Re = Rf + \beta\,(Rm - Rf)$$

where:

Re = the required return on common equity for a specific stock

Rf = the risk-free rate of return

Rm = the return required for the market as a whole

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific stock.

In order to calculate the CAPM, one must make assumptions about the risk-free rate of return, the market risk premium and the Beta. Since the cost of capital is forward looking, it is appropriate to use forward-looking estimate for the variables, if possible.

a. Fundamental Problems with the Capital Asset Pricing Model

Q.49 What are some of the limitations of the CAPM Model?

A. The intuitive basis of the CAPM is that investors will seek to be compensated for the relative systematic (or non-diversifiable) risk of a given stock in relation to a risk free investment and the broader market for equities. Many academics and practitioners question whether Beta, in the best of circumstances, can plausibly measure the true risk characteristics of a firm and advise that there are other risks that may influence investors' decisions. The CAPM assumes that any risk that can be diversified in an investors' portfolio, is diversified, and therefore irrelevant to the cost of capital. However, this assumption may not represent actual investor behavior; and it is likely that diversification reduces a firm's relevant risks less than the CAPM theory assumes. For example, a comprehensive study of Canadian stock returns concluded that:

> The empirical study on the Canadian equity market demonstrates the existence of size premia based on data from 1993 to 2007. Results also indicate that beta, the CAPM's risk measure, was a weak measure

> to explain expected returns for smaller firms as smaller firms have a high unsystematic risk component.[45]

To the extent that variables other than Beta are able to explain variations in return that are not explained by Beta, diversification does not eliminate all unsystematic risks and the CAPM cannot be considered to be an adequate measure of the cost of capital.

Though the CAPM has a plausible theoretical basis, its application also is often the source of controversy and exhaustive debate among practitioners. For example, the expected future market equity risk premium is difficult to quantify, and involves debates concerning the preference for ex-ante or ex-post methodologies, averaging conventions, time period covered, etc. The second most contested factor is the controversy surrounding Beta which has no theoretically correct method of quantification and has been shown to be a poor indicator of actual stock returns. Moreover, there is debate on whether Beta should be adjusted towards the market mean or the utility-sector mean, or whether it is appropriate to use a raw Beta without adjustment. All of these factors lead to questions on whether the CAPM method may reliably track the capital costs of a regulated utility.

Q.50 Would you elaborate on why the CAPM is an unreliable method for estimating the cost of common equity capital?

A. Application of the CAPM – and more specifically, estimation of investors' expectation of a forward-looking "Beta" – is based on the concept that the value of each individual stock (or other investment) has a reasonably fixed, known and measureable sensitivity to changes in the value of a market portfolio consisting of all other investments in the

[45] Wilhelm, K., "Size Premia in the Canadian Equity Market," *Journal of Business Valuation*, May 2009, p. 19.

economy. However, there are several fundamental problems with the CAPM that have been established in the finance literature.

First, there are no theoretically correct time intervals for measuring the returns and risks that are relevant for investors, but the calculated level of Beta can be very different when different measurement intervals are used. Therefore, the selection of time intervals for measuring Beta – and by extension the level of Beta – is an arbitrary decision that cannot be defended on either theoretical or empirical grounds.

Second, the Beta and risk-premium inputs to the CAPM model generally are based on historical rather than forecasted information. However, there is no theoretically correct *historical* time period (e.g., two years, five years, 10 years, etc.) over which to measure the *future* Beta that investors currently expect, and there is significant evidence that Beta does not remain constant from one period to the next. Thus, a Beta measured using historical data cannot provide an accurate estimate of the level of risk investors currently expect on a forward-looking basis.

Third, although several early studies conducted approximately 40 years ago were thought to have validated the accuracy of the CAPM, more complete empirical studies since that time have shown that the CAPM is not accurate and that the results of early studies may have been a statistical anomaly. In general, Beta estimates do not have a strong correlation with the returns earned on investments and therefore Beta estimates would not be expected to provide valid estimates of the relative cost of common equity.

Q.51 Why is there a fundamental problem with selecting the time intervals used in calculating Beta?

A. Although Beta is supposed to be the measure of how sensitive the return on a particular stock is relative to the return on a diversified market portfolio, there are no theoretically correct time intervals for measuring that sensitivity. For example, one could measure Beta using an annual interval that calculates the relationship between the return on a stock and the return on the market portfolio from one year to the next. However, it would be equally "correct" to measure Beta by calculating the relationship between the returns that occur each month. Similarly, the theory allows Beta to be measured using the rates of return that occur weekly, or daily, or any other time period the analyst chooses. Because there are no theoretically correct time intervals for measuring the returns, it is an arbitrary choice as to which time intervals to use. Many studies, including Levhari and Levy[46] and Hawawini[47], have shown that the level of Beta can be very different depending on the time interval selected for measuring returns. For example, Hawawini cites Eastman Kodak as one example where the Beta was 1.25 based on daily returns, but it was 0.93 based on monthly returns.[48] Discrepancies of this magnitude are not unusual when different return intervals are used to estimate the value of Beta. Because the level of Beta is sensitive to the time intervals of the returns used in its calculation, and the time intervals used are selected arbitrarily, the level of Beta used in a CAPM analysis ultimately is an arbitrarily selected number. An arbitrarily selected Beta cannot be considered to be a reasonable or accurate method for estimating the cost of common equity.

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[46] Levhari, D. and Levy, H., "The Capital Asset Pricing Model and the Investment Horizon," *Review of Economics and Statistics* (February 1977), 92-104.
[47] Hawawini, G., "Why Beta Shifts as the Return Interval Changes," *Financial Analysts Journal* (May-June 1983), 73-77.
[48] Ibid., p. 73.

Q.52 In regard to the second problem, why is it unreliable to simply use historical data to calculate the current forward-looking cost of common equity?

A. Investors' current requirements and expectations for the future are not necessarily the same as the past. Thus, even if we ignore the problem that there is no theoretically accurate or reliable way to measure what "Beta" has been in the past, there is no reason to believe that investors currently perceive the same risks and require the same premiums for risk that were experienced in the past. Instead, investors' current expectations for "Beta" are forward-looking and not historical. Moreover, it is not unusual for calculated Betas to shift from one period to the next in ways that appear to be unrelated to any changes in risk.

In addition to the proven inaccuracy and unreliability of Beta, the market risk premium is another important component of the CAPM equation that changes over time. Historical market risk premia are less reliable than reasonable forecasts because the historical average relationships between equity returns and bond yields may not reflect the current circumstances. When Canadian regulators rely on an equity risk premium formula to make annual generic adjustments to the allowed rate of return, they generally have relied on an assumption that the level of the risk premium should vary inversely with the level of interest rates. In contrast analysts who use the CAPM approach often ignore the current level of interest rates in estimating a risk premium.

Q.53 In regard to your third point, what evidence is there that the CAPM does not provide valid estimates of the cost of capital?

A. Although the early academic literature appeared to validate the CAPM, subsequent research casts serious doubt on its empirical validity. In a 1992 article, "The Cross Section of Expected Stock Returns," *Journal of Finance*, 47:427-465 (June 1992), Eugene Fama and Kenneth French examined the relationship between Beta and the returns earned by companies. This article essentially re-visited the research from the late 1960's and early 1970's that appeared to verify Beta as a reasonable measure of risk and required return. That earlier research primarily relied on data from the 1960's and found a significant correlation between actual stock returns and certain measures of Beta. In other words, stocks with high Betas tended to experience higher returns, and stocks with low Betas tended to experience lower returns. It was therefore assumed that "Beta" is an accurate measure of the risk that is relevant for determining the cost of capital.

The 1992 Fama and French article recognized that there are numerous ways to calculate "Beta" and the authors tested thousands of different Beta calculations over hundreds of different holding periods between 1963 and 1990. Their 1992 article found that there was no statistically significant relationship between Betas and stock returns in the vast majority of different time periods. In other words, Beta could not explain the level of returns on stocks and, therefore, one could not assume that Beta can accurately measure the risks that are relevant for determining the cost of capital. The notable exception to that finding occurred for some Betas generally measured during the 1960's. The ultimate conclusion of this comprehensive analysis was that Beta was not significantly related to stock returns, and that the supposed verification of Beta during the early 1970's was a statistical anomaly. Although they found that the level of Beta does not correlate well with the returns on common stocks, Fama and French found that firm size (with smaller companies requiring higher returns) and market-to-book ratio are the two variables that best explain the returns for common stocks.[49] With regard to these findings Value Line commented as follows:

> "Indeed, Professor Fama concluded, 'The fact is that Beta, as the sole variable explaining returns on stocks, is dead.' These findings support previous studies that have called into question the real-world applicability of the CAPM Beta, including papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial Economics, 1977). Never before, however, has the lack of a statistically significant relationship between beta and return been so rigorously and dramatically established."[50]

Q.54 What do you conclude with respect to the use of the CAPM for estimating the cost of common equity?

A. From a conceptual perspective, the CAPM has many weaknesses that make it an unreliable method for estimating the cost of common equity capital. In a 2004 article that reviewed the history of attempts to test the validity of the CAPM, Fama and French concluded that:

> "Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model."[51]

Similarly, the BCUC acknowledged the limitations of the CAPM in a 2009 decision, noting that the *"CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta."*[52] As a consequence, the BCUC gave little weight to the CAPM analyses and

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[49] Fama and French, "The Cross-Section of Expected Stock Returns," *Journal of Finance*, Vol. XLVII, No. 2, June 1992, 427-465.
[50] Value Line Industry Review, March 13, 1992, p. 1-8.
[51] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, Number 3, Summer 2004, at 25.
[52] British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure, December 16, 2009, p. 45.

set an allowed rate of return that was above the top of the range for the CAPM results.[53]

For all of the reasons discussed above, the CAPM should not be considered to be a valid or reliable method for estimating the cost of common equity capital for a regulated company.

3. Flotation Cost Adjustment to Cost of Capital

Q.55 What are flotation costs?

A. Flotation costs are 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.

Q.56 Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost-of-capital that the regulated company requires in order to raise capital on reasonable terms in the "primary" markets.

Q.57 Please describe the difference between "primary" and "secondary" markets for common equity.

A. When a company issues new common equity in order to raise cash for investment in plant, or, to otherwise run its operations, it does so in the "primary" market. The

[53] Ibid., at page 66.

"primary" market is defined very simply as the market in which the stock is first sold in order to raise cash funds to be used by the issuer. In this "primary" market, the company generally hires an investment banker, or a syndicate of bankers and brokers, to float its stock issue to the public. Associated with a company raising cash funds through a "primary" market sale of common equity there are significant costs of preparing and filing documents with regulatory agencies, and issuing prospectuses. In addition, in the "primary" market the issuing company generally must pay a significant percentage of the proceeds from the stock issuance to the investment banker, or the syndicate of bankers and brokers, who finds the investors who will provide cash to the issuing company.

Once stock has been issued to investors in the "primary market", those investors who initially provided cash to the issuing company may re-sell or "trade" the stock with other investors in the "secondary" market. Much of the trading in the "secondary" market occurs on stock exchanges and buyers and sellers are not required to file prospectuses with a stock exchange commission. The crucial difference between stock issued in the "primary" market and stock traded in the "secondary" market is that the issuing company does not receive any additional funds when its stock trades in the "secondary" market. Instead, the ownership of the stock merely changes hands between various investors. In addition, the brokerage fees associated with buying and selling stock in the "secondary" market generally are incurred by both the buyer and the seller, and are a small fraction of the level of the flotation costs incurred by a company that attempts to raise cash by issuing stock in the "primary" market.

Q.58 Have you quantified the cost of raising capital by issuing stock in the "primary" market?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital to a company. Schedule 8 shows a representative sample of flotation costs incurred with 173 new common stock or partnership unit issues by natural gas transmission and distribution companies between 2000 and 2011. Flotation costs associated with these new issues averaged 3.96 percent. This indicates that in order to be able to issue new common equity on reasonable terms, without diluting the value of the existing stockholders' investment, Intragaz must have an expected return that places a value on its equity that is approximately 4.00 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.040. This "primary" market return on equity is presented in Table 4 of my testimony with the results of the secondary market returns discussed previously.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common equity several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

In summary, when an ROE analysis is based on stock prices, dividend yields, Betas, and market risk premiums derived in the "secondary" market to estimate the required rate of return, a flotation cost adjustment is essential in order to account for the difference between (i) the market value of stocks traded between investors in the secondary markets and (ii) the net proceeds expected from stock issued in the primary market to raise capital for plant construction and utility operations.

V. SELECTION OF NATURAL GAS STORAGE PROXY COMPANIES

Q.59 Would you please describe the overall approach used in your ROE analyses of Intragaz' cost of common equity?

A. Because Intragaz must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other investments of a similar risk. In order to perform a DCF analysis, it is necessary to ascertain the market derived price of the company's stock. Since nearly all gas pipelines and storage companies, including Intragaz, are owned by larger, diversified companies, the operating companies for which the Régie sets rates often do not have publicly-traded common equity that would produce a market price that is required for ROE analysis. A direct, market-based cost of capital analysis of Intragaz as a stand-alone company is not possible since it is privately organized as a limited partnership between two diversified energy companies. As an alternative, I have used two proxy groups, a Canadian utility group and a U.S. natural gas pipeline and storage group that are most nearly similar in risk to Intragaz.

Q.60 Please describe why it was necessary to use two proxy groups?

A. I have used two proxy groups to bring an added perspective and information into the evaluation of a fair return for Intragaz, a pure-play Canadian gas storage company. Because there are no publicly-traded pure-play gas storage companies with sufficient information to conduct the analysis, I have selected a sample of Canadian utilities to provide a benchmark for the risks and resulting cost of capital of Canadian utilities in general. Then, to provide a check against the results of my primary proxy group and to add an additional perspective on the risks specific to a gas pipeline and storage entity, I have developed a sample of U.S. companies whose operations are primarily attributed to natural gas transmission and storage. With the information that I have collected from these two samples, I have assessed where Intragaz's risk lies relative to these two groups.

Q.61 Please describe how you selected your Canadian Utility proxy group?

A. I began with a list of companies that comprise the S&P/TSX Utilities Index in Canada. I eliminated companies whose primary business is power generation, on the basis of a substantially different risk profile than that of Intragaz. I also eliminated income funds or companies where there was inadequate data to perform the analyses. I arrived at a group of the following five companies.

- Canadian Utilities
- Enbridge, Inc.
- TransCanada Corp.
- Emera, Inc.
- Fortis, Inc.

Q.62 How did you establish the group of U.S. natural gas transmission and storage proxy companies that are risk appropriate for Intragaz?

A. I relied on a list of screening criteria to narrow the list of potential proxy companies. As Intragaz' business operations are 100 percent natural gas storage, it is difficult to develop a proxy group in which the members will have exactly the same risk. Therefore, after I identified a "short list" of potential companies, I conducted an extensive review of the potential proxy companies' business units, both pipeline assets and other business segments, to identify a group of companies that are of comparable risk to Intragaz. From this analysis, I concluded that five of the potential proxy companies were most comparable to Intragaz. The following screens were applied to establish my "short list" of potential proxy companies:

1. All of the companies have publicly-traded common stock or partnership units;
2. All companies must be covered by an investment information service, like Value Line.
3. All of the companies have at least 50% of the their assets or operating income derived from its natural gas storage or transmission operations;
4. All of the companies are currently paying cash dividends or distributions;
5. None of the companies has a credit rating below investment grade as established by either Moody's or Standard and Poor's;
6. None of the companies is engaged in significant transactions involving mergers, acquisitions or divestitures; and

7. All of the companies must have at least three years of historical data available and have paid a distribution during that time period.

Based on the application of these criteria, I have developed a group of potential proxy companies with risks reasonably comparable to those of Intragaz.

Q.63 What companies met these screening criteria?

A. The following five companies and MLPs met these criteria:

- Boardwalk Pipeline Partners, L.P ("Boardwalk");
- Spectra Energy Corp ("Spectra Energy");
- Spectra Energy Partners, L.P. ("Spectra LP");
- TC Pipelines, L.P. ("TC Pipelines");
- Williams Partners L.P ("Williams Partners").

Q.64 Why have you selected natural gas transmission pipeline companies as proxy companies for a pure-play storage entity?

A. Natural gas transmission companies share largely the same competitive and market risks of a pure-play storage entity. Both are widely exposed to contract attrition if more economic alternatives become available.

Q.65 How did you conduct your comparability analysis of each of the potential proxy companies?

A. In order to determine whether the proxy group developed to calculate Intragaz's cost of equity provides an appropriate comparison to the risks for Intragaz, it is necessary to examine the individual companies that comprise the potential proxy group.

In Schedule 3, I have provided a list of gas transmission pipelines and storage facilities owned by the companies that I included in my group of potential natural gas transmission and storage proxy companies. My determination as to whether each of these companies is sufficiently similar in risk to Intragaz was based on the relative financial and operating risk of the potential proxy companies. This included an assessment of the risk of other businesses that each company is engaged in, as well as the risk of the natural gas pipelines and storage facilities that are operated by the company.

Q.66 How do the overall risks of the U.S. natural gas pipeline proxy companies compare with the risks faced by Intragaz?

A. The proxy companies I have selected are the most reasonable companies to use to reflect the business operations and associated risks of Intragaz. As shown on Schedules 3 and 4, all of the natural gas pipeline proxy companies are significantly more diversified than Intragaz both in terms of geographic markets and lines of business. In addition, each of the proxy group companies has a portfolio of assets that source gas from more than one producing region and that reach multiple market areas, which serves to reduce their overall risk. However, most of their pipeline assets face various degrees of competition.

Intragaz is a small natural gas storage company that serves one single gas market and customer. Moreover, as discussed in Section III earlier in this testimony, storage operations face greater technological risks that a facility will fail to work properly. Although Intragaz faces no immediate competition compared to the pipelines and storage facilities owned by the proxy group, it lacks certainty that it will continue to be fully subscribed by Gaz Métro and lacks the benefit of diversification if Gaz Métro were to not renew its agreement with Intragaz. These risks related to technology, lack of diversification, and its small size, when offset by a generally lower level of direct competition, place Intragaz's operating risks somewhat above those of the typical company in the pipeline and storage company proxy group.

Q.67 Why have you placed primary reliance on the Canadian utility company proxy group?

A. While I consider the U.S. Pipeline and Storage company proxy group to be risk appropriate for Intragaz, I recognize the preference of the Régie for a proxy group of Canadian utility companies. As a result, my cost of equity recommendation is based primarily on the results of the Canadian Utility proxy group and is supported by the results of the U.S. Pipeline and Storage company proxy group.

VI. RESULTS OF ROE ANALYSES

A. DCF Analysis

1. Dividend Yield

Q.68 How did you calculate the dividend yields for the companies in your comparison groups?

A. The dividend yields were calculated for each company by dividing the current annualized dividend by the average of the stock prices for each company. For the price component of the calculation, I calculated the high and low price for each month during the six-month period from November 2011 through April 2012. The dividend yield was then calculated for each month using the most recent dividend for that period. The six dividend yields over this time period were then averaged to derive the dividend yield that was used in the DCF analysis. These calculations are shown on Schedule 5. These dividend yields are multiplied by the DCF model factor

(1 + .5 g) to reflect expected future dividend increases, to arrive at the dividend yield component of the DCF model.

2. Growth Rate Analysis

Q.69 Please describe the methods you used in estimating the future growth rate that investors expect from these companies?

A. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

Q.70 In your opinion, what are some of the underlying factors that will affect future growth rates for the companies in both proxy groups?

A. One important factor will be growth in the overall economy. Schedule 1, pages 1 and 2, shows national economic growth rates. The Canadian Gross Domestic Product has grown at an average annual rate of 5.4 percent during the past 30 years, and at a rate of approximately 4.5 percent during the past decade. The U.S. nominal GDP has also grown at an average annual rate of 5.4 percent over the past 30 years and at a rate of approximately 3.9 percent over the last decade. It is reasonable to expect that long-term future growth in the economy generally will be comparable to past growth rates in the 3.9 – 5.4 percent range.

Another factor will be demand for natural gas. Natural gas usage generally has been increasing in recent years and many analysts are expecting demand to increase steadily during the next decade and beyond. For example, the Energy Information Administration of the U.S. Department of Energy ("EIA") forecasts that gas consumption in the United States will grow from its current level of approximately

24 Tcf per year to approximately 26.5 Tcf per year in 2035.[54] This forecast is largely dependent on the demand for natural gas from the industrial and electric power sector. Steady increases in demand for gas transportation should be fueled by the availability of domestic and imported supplies, rapid growth in new areas of production, and the superior environmental characteristics of natural gas that should allow it to achieve a greater market share relative to other fuels.

Q.71 What are some of the other factors that will affect the growth rates of the proxy companies in the foreseeable future?

A. Natural gas resources will increasingly be required to serve new or growing markets. Many of the major new electric generation projects proposed or constructed in recent years have been for this purpose. Dramatic improvements in the efficiency of combined-cycle plants during the past two decades, along with the regulatory policies that require open access to the electric transmission grid, have created a very large demand for new gas-fired electric generating plants and pipeline capacity to supply these plants. Air quality and plant siting requirements, combined with increasingly stringent environmental regulations on coal-fired plants, have created an expectation of increases in demand for natural gas-fired generation in the future.

Pipelines also must add facilities to attach new gas supplies as the sources of existing supplies are depleted and new areas are developed. Many of the new pipeline facilities proposed in recent years have been designed to transport growing supplies from the Rocky Mountain and Powder River regions and the rapidly growing shale

[54] EIA, Annual Energy Outlook 2012 Early Release, Reference Case, Table 13 – Natural Gas Supply, Disposition, and Prices.

gas production areas throughout North America. Technological improvements and discoveries of enormous amounts of shale gas in formations throughout North America will create a need for large amounts of new pipeline construction and storage that may displace existing facilities that serve more distant sources. These various sources of new supplies are likely to contribute to growth in overall gas usage, and also may displace volumes from other supply basins. Consequently, as the natural gas industry becomes increasingly competitive, domestic pipeline and storage capacity and investment is likely to grow more rapidly than overall consumption, and many existing pipelines and storage facilities are becoming riskier. Finally, if growth in the regulated pipeline and storage industry slows, or if regulated returns become inadequate, we would expect to see these proxy companies directing a greater share of their investments toward unregulated investments that offer the opportunity of a reasonable return and that will sustain a relatively high level of growth.

Q.72 Please describe the growth rates used in your DCF analysis?

A. My DCF analysis is based on a constant growth model that relies on analysts' forecasts of growth rates. This DCF 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. Financial research and empirical literature indicate that analyst forecasts are the best available estimates for future growth rates. I selected available earnings growth estimates from SNL Financial for each of the proxy companies. My growth rates may be found on Schedule 6.

Q.73 How did you calculate the cost of capital using the DCF analysis?

A. These calculations are shown on Pages 1 and 2 of Schedule 7. In the DCF analysis, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .5g) and this product is added to the growth rate estimate to arrive at the investor-required return. As shown on Schedule 7 and in Table 4 below, the DCF analysis indicates a median secondary market cost of common equity of 11.33 percent and a median primary market cost of common equity of 11.78 percent for the Canadian utility proxy group. For the U.S. pipeline and storage proxy companies, the DCF analysis indicates a median secondary market cost of common equity of 10.83 percent and a median primary market cost of common equity of 11.26 percent. The primary market results are derived by multiplying the secondary market results by 1.040 (the estimated flotation cost).

Table 4: DCF Results for Proxy Companies

	Canadian Utility Proxy Group		**U.S. Pipeline and Storage Proxy Group**	
	Secondary Market	**Primary Market**	**Secondary Market**	**Primary Market**
High	12.95%	13.47%	12.28%	12.78%
3rd Quartile	11.53%	12.01%	11.72%	12.18%
2nd Quartile (MEDIAN)	**11.33%**	**11.78%**	**10.83%**	**11.26%**
1st Quartile	8.95%	9.31%	9.85%	10.25%
Low	8.27%	8.60%	9.61%	10.00%

B. Risk Premium Analyses

Q.74 Have you conducted additional analyses in determining the cost of capital to Intragaz?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adds to those yields a premium for the greater risk of investing in common stocks.

Q.75 What does your analysis of Canadian risk premium data indicate?

A. An estimate of the historical average size-adjusted risk premium for a company in Intragaz' size range can be calculated using data from a 2009 study by Klemens Wilhelm on "Size Premia in the Canadian Equity Market." In this study he analyzed the returns on all Canadian equities traded on the Toronto Stock Exchange ("TSX") throughout the period 1993 to 2007. With a deemed equity ratio of 50 percent Intragaz would have an equity value that falls in the 8th decile of the TSX companies (i.e., $36-$59 million). Canadian companies in this size range achieved a 10.60 percent premium over the yield on Canadian government bonds with a 10-year maturity.[55] The yield on 10-year Canadian government bonds was approximately 2.0 percent in April. When this yield is added to the 10.6 percent average risk premium experienced by companies in Intragaz's size range, the result is benchmark return requirement of 12.6 percent.

It should be noted that this benchmark estimate is based on the average historical risk premium, and that it is added to a bond yield that is currently far below the historical average. There is a general presumption that the expected risk premium should be inversely related to the level of the risk-free rate. Consequently, these risk premium benchmark measures likely understate the return required on common stocks at this time.

Q.76 What does your analysis of U.S. risk premium data indicate?

Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the returns on long-term corporate bonds by a premium of 540 basis points (5.4 percent) annually over a long period of time.[56] When this premium is added to the 4.76 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an

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[55] Wilhelm, K., "Size Premia in the Canadian Equity Market," *Journal of Business Valuation*, May 2009, Figure 4, p. 13.

[56] 2012 Ibbotson SBBI Valuation Yearbook, pg 23.

investor return requirement for large company stocks of 10.16 percent. However, over the long term companies in Intragaz's size range have had a premium of 880 basis points (8.8 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 13.56 percent.[57]

VII. SUMMARY AND CONCLUSIONS

Q.77 Would you please summarize the results of your cost of capital study of proxy companies?

A. Yes. I conducted DCF analyses on two proxy groups, a group of Canadian regulated energy utilities and secondly a group of U.S. natural gas pipeline and storage companies, that have a range of risks that includes risks roughly comparable to those of Intragaz. The results of my analyses are summarized in Table 5, below:

Table 5: Summary of Proxy Company DCF Analysis Results

	Canadian Regulated Energy Utilities	U.S. Pipeline & Storage Companies
High	13.47%	12.78%
3rd Quartile	12.01%	12.18%
2nd Quartile (MEDIAN)	**11.78%**	**11.26%**
1st Quartile	9.31%	10.25%
Low	8.60%	10.00%

The DCF analysis yields a median cost of capital for the Canadian regulated utility proxy group and the U.S. pipeline and storage company proxy group of 11.78 percent and 11.26 percent, respectively.

[57] 2012 Ibbotson SBBI Valuation Yearbook, pgs: 23, 87 and 92.

My analysis indicates that Intragaz has greater overall risk than is typical of companies in either of the proxy groups. Even with a service contract of 10 or more years, Intragaz's storage operations would still have considerably greater business risks than the Canadian utility proxy companies. However, much of this greater business risk would be offset by lower financial risk because Intragaz's deemed common equity ratio of 50 percent is significantly higher than the 37 percent median for the Canadian utilities. Under the circumstances assumed in my analysis, the overall risks for Intragaz would be slightly greater than those of the Canadian utilities.

Assuming that Intragaz obtains a service contract of at least 10 years, its business risks would be reasonably comparable to those of the U.S. Pipeline and Storage proxy companies. In addition, its 50 percent deemed common equity ratio would be nearly identical to the 50 percent median common equity ratio of these proxy companies. In my opinion, this combination suggests that Intragaz would have overall risks slightly greater than the U.S. pipeline and storage proxy group.

Although my analyses indicate that Intragaz would have slightly greater risks than is typical for the proxy groups, I have not added an additional risk premium to my estimates of the cost of capital. Consequently, my estimated cost of common equity capital for Intragaz is the minimum return actually required to enable Intragaz to attract common equity capital on reasonable terms.

Q.78 What are the components of your median return on equity estimates for Intragaz based on each proxy group?

A. Schedule 10 shows the primary components for the rate of return estimates for Intragaz based on each proxy group. The median Canadian utility company had an adjusted dividend yield of 4.23 percent and an expected growth rate of 7.10 percent. The total secondary cost of equity for the median proxy company is 11.33 percent, which becomes 11.78 percent after the adjustment for flotation costs. Using the same method on the U.S. pipeline and storage proxy group, the median company had an adjusted dividend yield of 6.83 percent and an estimated growth rate of 4.00 percent. When added together, the indicated secondary market cost of equity is 10.83 percent. When multiplied times 1.04 to provide a 4 percent flotation cost adjustment, the required return on equity is 11.26 percent.

Q.79 Please summarize your conclusions as to the appropriate return on equity for Intragaz.

A. If it obtains a contract of 10 or more years with Gaz Métro, Intragaz would have considerably greater business risk than the Canadian Utility proxy group because of its small size and the fact that its earnings are dependent on a single customer and market. In regard to financial risk, a deemed capital structure of 50 percent common equity for Intragaz would contain less leverage and financial risk than the Canadian Utility proxy companies. In comparison with the U.S. pipeline and storage proxy companies, under the same assumptions, Intragaz would have slightly greater business risk but approximately the same leverage as the U.S. Pipeline and Storage proxy companies. This combination of business and financial risk suggests that the overall risk implied for Intragaz common equity is generally comparable to, but slightly greater than, that of the companies in both of the proxy groups.

In my opinion, 11.75 percent – a return very close to the median result for the Canadian utility company proxy group – is the cost of common equity capital for Intragaz.

Q.80 Is your recommended rate of return reasonable in comparison with your benchmark measures?

A. Yes. Although they are likely understated due to unusually low bond yields at this time, the benchmark analyses, as shown in Table 6, indicate the following:

Table 6: Benchmark Analyses

Risk Premium Return Based On:	
- Canadian Government Bonds:	
v. Small Companies	12.6%
- U.S. Corporate Bonds:	
v. Large Companies (Large Cap)	10.16%
v. Small Companies (Low Cap)	13.56%

The risk premium analyses indicate that the 11.75 percent estimated cost of common equity for Intragaz implies a current risk premium that is well below the average long-run premium over bond yields historically experienced by either Canadian or U.S. common stocks in Intragaz's size range.

Q.81 Does this conclude your Prepared Direct Testimony?

A. Yes

Intragaz Limited Partnership

General Economic Statistics - Canada

1981-2011

		[A]	[B]	[C]	[D]	[E]
		Percentage Price Changes				
Line No.	Year	Consumer Price Index - Canada	GDP Implicit Price Deflator - Canada	Real GDP Growth - Canada	Nominal GDP ($Billions)	Nominal GDP Growth
1	1981	12,5%	10,7%	3,5%	360,5	
2	1982	10,8%	8,5%	-2,9%	379,9	5,4%
3	1983	5,9%	5,5%	2,7%	411,4	8,3%
4	1984	4,3%	3,1%	5,8%	449,6	9,3%
5	1985	4,0%	3,2%	4,8%	485,7	8,0%
6	1986	4,2%	3,1%	2,4%	512,5	5,5%
7	1987	4,4%	4,6%	4,3%	558,9	9,1%
8	1988	4,0%	4,5%	5,0%	613,1	9,7%
9	1989	5,0%	4,5%	2,6%	657,7	7,3%
10	1990	4,8%	3,3%	0,2%	679,9	3,4%
11	1991	5,6%	2,9%	-2,1%	685,4	0,8%
12	1992	1,5%	1,3%	0,9%	700,5	2,2%
13	1993	1,9%	1,4%	2,3%	727,2	3,8%
14	1994	0,2%	1,1%	4,8%	770,9	6,0%
15	1995	2,1%	2,2%	2,8%	810,4	5,1%
16	1996	1,6%	1,6%	1,6%	836,9	3,3%
17	1997	1,6%	1,3%	4,2%	882,7	5,5%
18	1998	1,0%	-0,5%	4,1%	915,0	3,7%
19	1999	1,7%	1,7%	5,5%	982,4	7,4%
20	2000	2,7%	4,1%	5,2%	1 076,6	9,6%
21	2001	2,5%	1,1%	1,8%	1 108,0	2,9%
22	2002	2,3%	1,1%	2,9%	1 152,9	4,0%
23	2003	2,8%	3,3%	1,9%	1 213,2	5,2%
24	2004	1,9%	3,2%	3,1%	1 290,9	6,4%
25	2005	2,2%	3,3%	3,0%	1 373,8	6,4%
26	2006	2,0%	2,7%	2,8%	1 450,4	5,6%
27	2007	2,1%	3,2%	2,2%	1 529,6	5,5%
28	2008	2,4%	4,1%	0,7%	1 603,4	4,8%
29	2009	0,3%	-1,9%	-2,8%	1 529,0	-4,6%
30	2010	1,8%	3,0%	3,2%	1 624,6	6,3%
31	2011	2,9%	3,2%	2,5%	1 720,7	5,9%
	Average Rate of Change: [1]					
32	1981-2011	3,3%	3,0%	2,6%	5,3%	5,4%
33	1991-2011	2,0%	2,1%	2,4%	4,7%	4,7%
34	2001-2011	2,1%	2,4%	1,9%	4,5%	4,5%

[1] Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Sources: Statistics Canada, Databases & Tables, website (http://www5.statcan.gc.ca/cansim)
OECD (2010), "Main Economic Indicators - complete database", Main Economic Indicators (database),http://dx.doi.org/10.1787/data-00052-en (Accessed on date)

Original: June 25, 2012
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Intragaz Limited Partnership

General Economic Statistics - United States

1981-2011

		[A]	[B]	[C]	[D]	[E]
		Percentage Price Changes				
Line No.	Year	Consumer Price Index - U.S.	GDP Implicit Price Deflator - U.S.	Real GDP Growth - U.S.	Nominal GDP - U.S. ($Billions)	Nominal GDP Growth - U.S.
1	1981	10,3%	9,4%	2,5%	3 126,8	
2	1982	6,2%	6,1%	-1,9%	3 253,2	4,0%
3	1983	3,2%	4,0%	4,5%	3 534,6	8,6%
4	1984	4,3%	3,8%	7,2%	3 930,9	11,2%
5	1985	3,6%	3,0%	4,1%	4 217,5	7,3%
6	1986	1,9%	2,2%	3,5%	4 460,1	5,8%
7	1987	3,6%	2,9%	3,2%	4 736,4	6,2%
8	1988	4,1%	3,4%	4,1%	5 100,4	7,7%
9	1989	4,8%	3,8%	3,6%	5 482,1	7,5%
10	1990	5,4%	3,9%	1,9%	5 800,5	5,8%
11	1991	4,2%	3,5%	-0,2%	5 992,1	3,3%
12	1992	3,0%	2,4%	3,4%	6 342,3	5,8%
13	1993	3,0%	2,2%	2,9%	6 667,4	5,1%
14	1994	2,6%	2,1%	4,1%	7 085,2	6,3%
15	1995	2,8%	2,1%	2,5%	7 414,7	4,7%
16	1996	3,0%	1,9%	3,7%	7 838,5	5,7%
17	1997	2,3%	1,8%	4,5%	8 332,4	6,3%
18	1998	1,6%	1,1%	4,4%	8 793,5	5,5%
19	1999	2,2%	1,5%	4,8%	9 353,5	6,4%
20	2000	3,4%	2,2%	4,1%	9 951,5	6,4%
21	2001	2,8%	2,3%	1,1%	10 286,2	3,4%
22	2002	1,6%	1,6%	1,8%	10 642,3	3,5%
23	2003	2,3%	2,1%	2,5%	11 142,2	4,7%
24	2004	2,7%	2,8%	3,5%	11 853,3	6,4%
25	2005	3,4%	3,3%	3,1%	12 623,0	6,5%
26	2006	3,2%	3,2%	2,7%	13 377,2	6,0%
27	2007	2,8%	2,9%	1,9%	14 028,7	4,9%
28	2008	3,8%	2,2%	-0,3%	14 291,5	1,9%
29	2009	-0,4%	1,1%	-3,5%	13 939,0	-2,5%
30	2010	1,6%	1,2%	3,0%	14 526,5	4,2%
31	2011	3,2%	2,1%	1,7%	15 094,4	3,9%
	Average Rate of Change: [1]					
32	1981-2011	3,3%	2,8%	2,7%	5,4%	5,4%
33	1991-2011	2,6%	2,2%	2,5%	4,7%	4,7%
34	2001-2011	2,5%	2,3%	1,6%	3,9%	3,9%

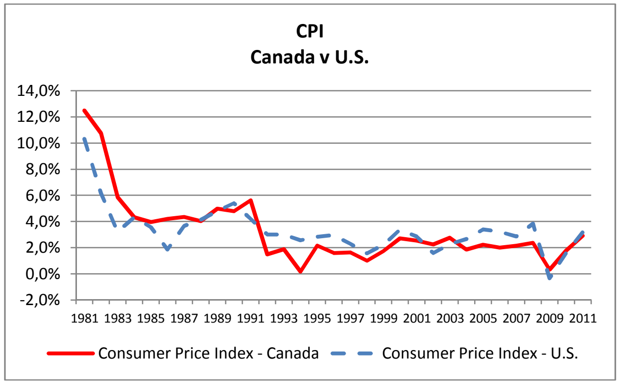
[1] Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

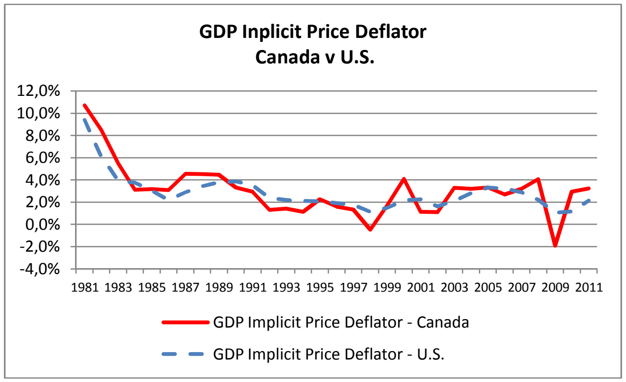
Sources: Department of Labor, Bureau of Labor Statistics, Databases & Tables, website (http://www.bls.gov/data) and Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, website (http://www.bea.gov/national/nipaweb/index.asp)

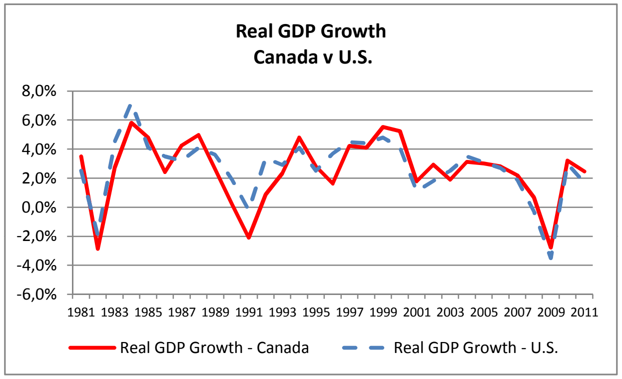
Intragaz Limited Partnership

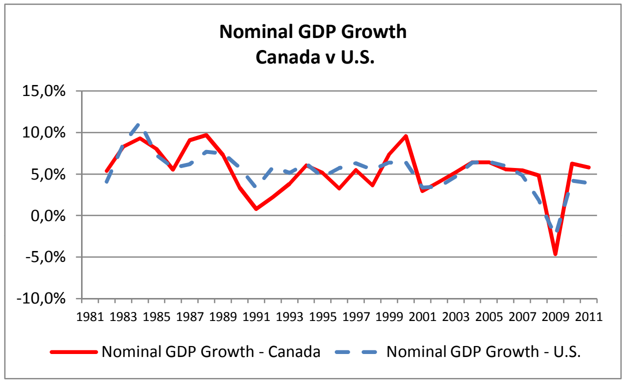
General Economic Statistics - Canada and the U.S.

1981-2011









Sources: Department of Labor, Bureau of Labor Statistics, Databases & Tables,
website (http://www.bls.gov/data) and Department of Commerce, Bureau of Economic Analysis,
National Economic Accounts, website (http://www.bea.gov/national/nipaweb/index.asp)

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OECD (2010), "Main Economic Indicators - complete database", Main Economic Indicators
(database),http://dx.doi.org/10.1787/data-00052-en (Accessed on date)

Intragaz Limited Partnership

Canadian Bond Yield Averages
January 2008 - February 2012

			[A]	[B]	[C]	[D]	[E]	[F]
			30-Year	Average	Public Utility Bonds		Credit Spreads	
Line No.			Long Bonds	Corporate	A-Rated	BBB-Rated	A-Rated	BBB-Rated
1	2008	JAN	4,11	6,42	5,48	5,81	1,37	1,71
2		FEB	4,19	6,59	5,43	5,79	1,24	1,60
3		MAR	4,01	6,62	5,34	5,69	1,33	1,68
4		APR	4,11	6,78	5,51	5,79	1,41	1,68
5		MAY	4,09	6,80	5,55	5,81	1,46	1,72
6		JUN	4,13	6,87	5,57	5,91	1,44	1,78
7		JUL	4,10	6,87	5,58	5,92	1,48	1,82
8		AUG	4,04	6,88	5,67	5,86	1,63	1,82
9		SEP	4,03	7,32	6,18	6,36	2,15	2,34
10		OCT	4,18	7,93	6,76	7,13	2,59	2,95
11		NOV	4,13	7,84	6,75	6,95	2,61	2,82
12		DEC	3,62	7,93	6,47	6,81	2,86	3,20
13	2009	JAN	3,62	8,14	6,74	7,03	3,12	3,41
14		FEB	3,68	7,81	6,67	6,88	2,99	3,20
15		MAR	3,63	7,56	6,43	6,68	2,80	3,05
16		APR	3,70	7,56	6,48	6,79	2,78	3,09
17		MAY	3,93	7,22	6,16	6,53	2,22	2,60
18		JUN	3,96	6,58	5,61	5,94	1,66	1,98
19		JUL	3,96	6,36	5,56	5,87	1,60	1,91
20		AUG	3,95	6,05	5,31	5,59	1,36	1,64
21		SEP	3,89	6,13	5,28	5,59	1,39	1,70
22		OCT	3,93	6,20	5,35	5,56	1,42	1,63
23		NOV	3,94	6,06	5,31	5,59	1,37	1,65
24		DEC	4,01	6,29	5,59	5,84	1,59	1,84
25	2010	JAN	4,05	5,95	5,34	5,71	1,28	1,65
26		FEB	4,04	5,99	5,39	5,71	1,35	1,67
27		MAR	4,06	5,91	5,37	5,62	1,30	1,56
28		APR	4,07	5,87	5,29	5,48	1,21	1,41
29		MAY	3,83	5,86	5,36	5,50	1,52	1,66
30		JUN	3,74	5,71	5,18	5,36	1,44	1,62
31		JUL	3,73	5,75	5,19	5,37	1,46	1,64
32		AUG	3,57	5,52	4,98	5,07	1,41	1,50
33		SEP	3,48	5,42	4,86	4,97	1,38	1,49
34		OCT	3,44	5,49	4,93	5,05	1,50	1,61
35		NOV	3,58	5,57	4,95	5,08	1,37	1,50
36		DEC	3,62	5,60	4,96	5,16	1,34	1,54

Intragaz Limited Partnership

Canadian Bond Yield Averages
January 2008 - February 2012

			[A]	[B]	[C]	[D]	[E]	[F]
			30-Year	Average	Public Utility Bonds		Credit Spreads	
Line No.			Long Bonds	Corporate	A-Rated	BBB-Rated	A-Rated	BBB-Rated
37	2011	JAN	3,68	5,71	5,13	5,28	1,44	1,60
38		FEB	3,80	5,65	5,03	5,23	1,23	1,43
39		MAR	3,74	5,74	5,16	5,29	1,42	1,55
40		APR	3,76	5,69	5,12	5,25	1,36	1,49
41		MAY	3,56	5,52	4,94	5,02	1,37	1,46
42		JUN	3,46	5,60	4,99	5,09	1,53	1,63
43		JUL	3,39	5,31	4,70	4,82	1,31	1,43
44		AUG	3,07	5,32	4,69	4,82	1,62	1,75
45		SEP	2,84	5,13	4,41	4,50	1,58	1,66
46		OCT	2,91	5,28	4,51	4,57	1,60	1,66
47		NOV	2,73	5,14	4,29	4,43	1,56	1,70
48		DEC	2,55	4,91	4,05	4,12	1,50	1,58
49	2012	JAN	2,56	4,74	3,94	4,02	1,38	1,46
50		FEB	2,62	4,69	3,98	4,04	1,36	1,42
51		MAR	2,67	4,69	4,01	4,06	1,34	1,39
52		APR	2,62	4,72	4,08	4,18	1,46	1,56

Sources:
[A] Bloomberg, Canada Government Generic 30-Year Long Bond
[B] Bloomberg, Canada Corporate Average Bond Index (Averages A and BBB)
[C] Bloomberg, Fair Value A-Rated Utility Bond Index
[D] Bloomberg, Fair Value BBB-Rated Utility Bond Index
[E] Equals [C] − [A]
[F] Equals [D] − [A]

Intragaz Limited Partnership

U.S. Bond Yield Averages
January 2008 - February 2012

			[A]	[B]	[C]	[D]	[E]	[F]
			30-Year	Average	Public Utility Bonds		Credit Spreads	
Line No.			T-Bonds	Corporate	A-Rated	Baa-Rated	A-Rated	Baa-Rated
1	2008	JAN	4,33	6,02	6,02	6,35	1,68	2,01
2		FEB	4,51	6,24	6,21	6,60	1,70	2,08
3		MAR	4,38	6,23	6,21	6,68	1,83	2,30
4		APR	4,44	6,29	6,29	6,81	1,85	2,37
5		MAY	4,60	6,31	6,28	6,79	1,68	2,20
6		JUN	4,68	6,43	6,38	6,93	1,70	2,24
7		JUL	4,56	6,44	6,40	6,97	1,84	2,41
8		AUG	4,50	6,42	6,37	6,98	1,87	2,48
9		SEP	4,27	6,50	6,49	7,15	2,22	2,88
10		OCT	4,16	7,56	7,56	8,58	3,40	4,42
11		NOV	3,98	7,65	7,60	8,98	3,62	5,00
12		DEC	2,85	6,71	6,52	8,11	3,68	5,27
13	2009	JAN	3,10	6,59	6,39	7,90	3,29	4,80
14		FEB	3,59	6,64	6,30	7,74	2,71	4,15
15		MAR	3,64	6,84	6,42	8,00	2,79	4,36
16		APR	3,76	6,85	6,48	8,03	2,73	4,27
17		MAY	4,24	6,79	6,49	7,76	2,25	3,52
18		JUN	4,51	6,52	6,20	7,30	1,69	2,79
19		JUL	4,40	6,17	5,97	6,87	1,56	2,47
20		AUG	4,37	5,83	5,71	6,36	1,34	1,99
21		SEP	4,19	5,61	5,53	6,12	1,34	1,93
22		OCT	4,19	5,63	5,55	6,14	1,36	1,95
23		NOV	4,31	5,68	5,63	6,17	1,32	1,86
24		DEC	4,50	5,78	5,79	6,26	1,29	1,76
25	2010	JAN	4,60	5,76	5,77	6,16	1,17	1,55
26		FEB	4,62	5,86	5,87	6,25	1,25	1,63
27		MAR	4,65	5,81	5,84	6,22	1,20	1,58
28		APR	4,69	5,80	5,81	6,19	1,12	1,50
29		MAY	4,28	5,52	5,50	5,97	1,22	1,69
30		JUN	4,12	5,52	5,46	6,18	1,34	2,06
31		JUL	3,99	5,32	5,26	5,98	1,27	1,99
32		AUG	3,80	5,05	5,01	5,55	1,21	1,75
33		SEP	3,77	5,05	5,01	5,53	1,24	1,76
34		OCT	3,87	5,15	5,10	5,62	1,23	1,75
35		NOV	4,19	5,37	5,37	5,85	1,18	1,66
36		DEC	4,42	5,55	5,56	6,04	1,14	1,62

Intragaz Limited Partnership

U.S. Bond Yield Averages

January 2008 - February 2012

			[A]	[B]	[C]	[D]	[E]	[F]
			30-Year	Average	Public Utility Bonds		Credit Spreads	
Line No.			T-Bonds	Corporate	A-Rated	Baa-Rated	A-Rated	Baa-Rated
37	2011	JAN	4,52	5,56	5,57	6,06	1,05	1,54
38		FEB	4,65	5,66	5,68	6,10	1,03	1,45
39		MAR	4,51	5,55	5,56	5,97	1,05	1,46
40		APR	4,50	5,56	5,55	5,98	1,05	1,48
41		MAY	4,29	5,33	5,32	5,74	1,03	1,45
42		JUN	4,23	5,30	5,26	5,67	1,03	1,44
43		JUL	4,28	5,30	5,26	5,70	0,98	1,42
44		AUG	3,65	4,79	4,69	5,22	1,04	1,57
45		SEP	3,18	4,60	4,48	5,11	1,30	1,93
46		OCT	3,12	4,60	4,52	5,24	1,40	2,12
47		NOV	3,01	4,39	4,25	4,93	1,24	1,92
48		DEC	2,99	4,47	4,33	5,07	1,34	2,08
49	2012	JAN	3,01	4,45	4,34	5,06	1,33	2,05
50		FEB	3,11	4,42	4,36	5,02	1,25	1,91
51		MAR	3,28	4,54	4,48	5,13	1,20	1,85
52		APR	3,18	4,49	4,40	5,11	1,22	1,93

Sources:
[A] Bloomberg, U.S. Government Generic 30-Year Treasury Bond
[B] Bloomberg, Moody's Corporate Average Bond Index
[C] Bloomberg, Moody's A-Rated Utility Bond Index
[D] Bloomberg, Moody's Baa-Rated Utility Bond Index
[E] Equals [C] − [A]
[F] Equals [D] − [A]

Intragaz Limited Partnership

Canadian Utility Companies
2011 Operating Data

Line No.	Company	[A] Assets ($000,000)	[B] Operating Revenues ($000,000)	[C] Operating Income ($000,000)
1	Canadian Utilities Limited	$11 696	$2 999	$515
2	Emera Inc.	$6 924	$2 040	$241
3	Enbridge Inc.	$34 343	$19 402	$1 891
4	Fortis Inc.	$13 562	$3 747	$766
5	TransCanada Corporation	$48 995	$9 139	$3 221
6	High	$48 995	$19 402	$3 221
7	Median	**$13 562**	**$3 747**	**$766**
8	Low	$6 924	$2 040	$241
9	Intragaz L.P.	**$123,0**	**$22,7**	**$12,7**
	Intragaz L.P. % of:			
10	Proxy Company Median	**0,91%**	**0,61%**	**1,66%**

Sources: Proxy Group - Annual Reports, SNL

Intragaz Limited Partnership

Natural Gas Pipeline & Storage Proxy Companies
2011 Operating Data

Line No.	Company	[A] Assets ($000,000)	[B] Operating Revenues ($000,000)	[C] Operating Income ($000,000)
1	Boardwalk Pipeline Partners, LP	$6 971	$1 139	$393
2	Spectra Energy Corp	$28 138	$5 351	$2 263
3	Spectra Energy Partners, LP	$2 457	$205	$196
4	TC Pipelines, LP	$2 082	$224	$209
5	Williams Partners L.P.	$14 380	$6 729	$1 754
6	High	$28 138	$6 729	$2 263
7	Median	**$6 971**	**$1 139**	**$393**
8	Low	$2 082	$205	$196
9	Intragaz L.P.	**$123,0**	**$22,7**	**$12,7**
	Intragaz L.P. % of:			
10	Proxy Company Median	**1,76%**	**1,99%**	**3,23%**

Sources: Proxy Group - SEC Form 10-K, SNL

Intragaz Limited Partnership

Bond Ratings of
Canadian Utility Companies

Line No.	Company	Ticker	Standard & Poor's [1]	Moody's [1]
		[A]	[B]	[C]
1	Canadian Utilities Limited	CU	A	NR
2	Emera Inc.	EMA	BBB+	NR
3	Enbridge Inc.	ENB	A-	Baa1
4	Fortis Inc.	FTS	A-	NR
5	TransCanada Corporation	TRP	A-	Baa1

Source: SNL Financial

[1] The credit rating is the corporate credit rating where available. Otherwise, it is the senior unsecured rating.

Intragaz Limited Partnership

Bond Ratings of
Natural Gas Pipeline & Storage Proxy Companies

		[A]	[B]	[C]
Line No.	**Company**	**Ticker**	**Standard & Poor's [1]**	**Moody's [1]**
1	Boardwalk Pipeline Partners, LP	BWP	BBB	NR
2	Spectra Energy Corp	SE	BBB+	NR
3	Spectra Energy Partners, LP	SEP	BBB	Baa3
4	TC Pipelines, LP	TCP	BBB	Baa2
5	Williams Partners L.P.	WPZ	BBB	Baa2

Source: SNL Financial

[1] The credit rating is the corporate credit rating where available. Otherwise, it is the senior unsecured rating.

Intragaz Limited Partnership

Interstate Pipeline and Storage Companies Owned by U.S. Proxy Group

Parent/Pipeline	Basin(s)/Hub(s) to Which Pipeline is Tied	Major Downstream Markets Served
Boardwalk Pipeline Partners, LP		
Texas Gas Transmission	Gulf Coast, E. TX, N. LA	Southern IN Western/Central KY Western TN Southern OH
Gulf South Pipeline	S. TX, E. TX, LA, Gulf Coast	Eastern TX Louisiana Southern MS Southern AL/Western FL
Gulf Crossing Pipeline	Barnett Shale, TX Caney/Woodford Shale, OK	Northeast LA
Bistineau Storage Facility (77.7 bcf) 92% interest	Depleted reservoir facility, LA	
Spectra Energy Corp		
Texas Eastern Transmission Co.	Gulf Coast, S. TX, E. TX, E. LA, S. LA	New York/New Jersey Philadelphia Central/Southern OH Central KY Southern IN Southern IL Central AR Southeast TX
Algonquin Gas Transmission	Gulf Coast (via TETCo)	New England
Maritimes and Northeast Pipeline (78% interest)	Offshore Nova Scotia	New England
Southeast Supply Header (50% interest)	Perryville Hub	Mobile Bay/Gulfstream
Bobcat (14 bcf)	Salt cavern, St. Landry Parish, LA	
Market Hub Partners - Egan (29 bcf) 50% interest	Salt cavern, Acadia Parish, LA	
Market Hub Partners - Moss Bluff (22 bcf) (50% interest)	Salt cavern, Liberty County, TX	
Steckman Ridge (12 bcf) (50% interest)	Depleted reservoir, Beford County, PA	
Dawn Facility (155 bcf) Operated by subsidiary Union Gas	Depleted reservoirs, Ontario, Canada	

Intragaz Limited Partnership

Interstate Pipeline and Storage Companies Owned by U.S. Proxy Group

Parent/Pipeline	**Basin(s)/Hub(s) to Which Pipeline is Tied**	**Major Downstream Markets Served**
Spectra Energy Partners, LP		
East Tennessee System	Gulf Coast (via TETCo, CGLF, TGP)	Central/Eastern TN Western VA
Ozark Gas System	Arkoma Basin, OK Fayetteville Shale	Southeastern MO/Northern AR TETCo, TXG, NGPL, CEGT
Gulfstream Natural Gas System (49% interest)	Mobile Bay, AL	Southern FL
Saltville (5.5 bcf)	Salt cavern, Saltville, VA	
Market Hub Partners - Egan (29 bcf) (50% interest)	Salt cavern, Acadia Parish, LA	
Market Hub Partners - Moss Bluff (22 bcf) (50% interest)	Salt cavern, Liberty County, TX	
TC PipeLines, LP		
Northern Border Pipeline Company (50% interest)	Canadian Border Williston Basin, MT/ND	North Hayden, IA Mid-West
North Baja	Mexican Border Costa Azul LNG Terminal	Palo Verde Elec. Gen./EPNG
Tuscarora Gas Transmission Company	WCSB (via GTNW)	Western NV
Great Lakes Gas Transmission L.P. (46.5% interest)	WCSB (via TCPL)	Dawn (MI/Canada Border) Central Michigan Northeastern MN
Storage contracted through TransCanada		

Intragaz Limited Partnership

Interstate Pipeline and Storage Companies Owned by U.S. Proxy Group

Parent/Pipeline	Basin(s)/Hub(s) to Which Pipeline is Tied	Major Downstream Markets Served
Williams Partners L.P.		
Transcontinental Gas Pipe Line Company	TX/LA/MS Offshore Gulf	Mid-Atlantic Southeast Gulf States
Northwest Pipeline	San Juan Basin	CO, UT, WY, ID Pacific Northwest Canadian Border
Gulfstream Natural Gas System (24.5% interest)	Mobile Bay, AL	Southern FL
Black Marlin Pipeline LLC	Offshore (TX)	Galveston, TX
Discovery Gas Transmission LLC (60.0% interest)	Offshore (LA)	Louisiana
Jackson Prairie (23 bcf) Operated by subsidiary NW Pipeline (33.3% interest)	Underground reservoir, Lewis County, WA	

Notes:
- Source: Company websites, Pipeline Informational Postings, Platts North American Natural Gas System Map (2008/2009 Edition).

Intragaz Limited Partnership

Proxy Group Companies
2011 Business Segment Data

Boardwalk Pipeline Partners, LP

	Total	Gas Transportation	Parking and Lending	Gas Storage	Other
Operating Income	$393	$393	$0	$0	$0
Percent of Total	100%	100%	0%	0%	0%
Segment Assets	$6 971	$6 366	$0	276	329
Percent of Total	100%	91%	0%	4%	5%

Spectra Energy Corp

	Total	U.S. Transmission	Distribution	Western Canada Transmission & Processing	Field Service	Other	Eliminations
Operating Income	$2 263	$983	$425	$510	$449	($104)	$0
Percent of Total	100%	43%	19%	23%	20%	-5%	0%
Segment Assets	$28 138	$11 783	$5 551	$5 649	$1 157	$4 535	($537)
Percent of Total	100%	42%	20%	20%	4%	16%	-2%

Spectra Energy Partners, LP

	Total	Gas Transportation & Storage
Operating Income	$196	$196
Percent of Total	100%	100%
Segment Assets	$2 457	$2 457
Percent of Total	100%	100%

Intragaz Limited Partnership

Proxy Group Companies
2011 Business Segment Data

TC PipeLines, LP

	Total	Pipelines
Operating Income	$209	$209
Percent of Total	100%	100%
Segment Assets	$2 082	$2 082
Percent of Total	100%	100%

Williams Partners L.P.

	Total	Gas Pipeline	Midstream	Other	Eliminations
Operating Income	$1 755	$615	$1 139	$0	$1
Percent of Total	100%	35%	65%	0%	0%
Segment Assets	$14 380	$8 348	$6 591	$226	-785
Percent of Total	100%	58%	46%	2%	-5%

Canadian Utilities

	Total	Utilities	Energy	ATCO Australia	Corporate & Other	Intersegment Eliminations
Operating Income	$515	$305	$165	($32)	$72	$5
Percent of Total	100%	59%	32%	-6%	14%	1%
Segment Assets	$11 696	$7 903	$1 891	$1 340	$728	($166)
Percent of Total	100%	68%	16%	11%	6%	-1%

Intragaz Limited Partnership

Proxy Group Companies
2011 Business Segment Data

Fortis, Inc.

	Total	FortisBC Energy Companies - Canadian	Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	Non-regulated - Fortis Generation	Non-regulated - Fortis Properties	Corporate and Other	Intersegment Eliminations
Operating Income	$766	$296	$363	$40	$21	56	12	-22
Percent of Total	100%	39%	47%	5%	3%	7%	2%	-3%
Segment Assets	$13 562	$5 316	$6 143	$856	546	610	482	-391
Percent of Total	100%	39%	45%	6%	4%	4%	4%	-3%

Enbridge, Inc.

	Total	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate
Operating Income	$1 891	$872	$408	$514	$145	($48)
Percent of Total	100%	46%	22%	27%	8%	-3%
Segment Assets	$34 343	$12 366	$7 713	$4 968	5245	4051
Percent of Total	100%	36%	22%	14%	15%	12%

Emera

	Total	Nova Scotia Power, Inc.	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other and Eliminations
Operating Income	$241	$124	$37	$47	$20	$14
Percent of Total	100%	51%	15%	19%	8%	6%
Segment Assets	$6 924	$3 897	$963	$849	545,8	669
Percent of Total	100%	56%	14%	12%	8%	10%

Intragaz Limited Partnership

Proxy Group Companies
2011 Business Segment Data

TransCanada Corporation

	Total	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate
Operating Income	$3 221	$1 981	$457	$883	($100)
Percent of Total	100%	62%	14%	27%	-3%
Segment Assets	$48 995	$23 669	$9 439	$14 276	1611
Percent of Total	100%	48%	19%	29%	3%

Sources: Company 2010 SEC Form 10-Ks, SNL, Annual Reports

Intragaz Limited Partnership

Canadian Utility Companies
Dividend Yields
November 2011 - April 2012

	Symbol	Yield
Canadian Utilities Limited	CU	2,67%
Emera Inc.	EMA	4,08%
Enbridge Inc.	ENB	2,81%
Fortis Inc.	FTS	3,59%
TransCanada Corporation	TRP	4,00%

Average	3,43%
Median	3,59%

Canadian Utilities Limited	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	69,87	64,78	67,325	1,77	2,63%
Mar-12	68,12	64,40	66,26	1,77	2,67%
Feb-12	65,98	60,26	63,12	1,77	2,80%
Jan-12	62,18	59,63	60,905	1,61	2,64%
Dec-11	62,49	59,00	60,745	1,61	2,65%
Nov-11	62,95	59,56	61,255	1,61	2,63%
Average					**2,67%**

Emera Inc.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	35,11	33,51	34,31	1,35	3,93%
Mar-12	34,93	33,16	34,045	1,35	3,97%
Feb-12	33,56	32,31	32,935	1,35	4,10%
Jan-12	33,21	32,05	32,63	1,35	4,14%
Dec-11	33,66	31,66	32,66	1,35	4,13%
Nov-11	33,03	31,02	32,025	1,35	4,22%
Average					**4,08%**

Intragaz Limited Partnership

Canadian Utility Companies
Dividend Yields
November 2011 - April 2012

Enbridge Inc	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	41,40	38,34	39,87	1,13	2,83%
Mar-12	39,10	36,47	37,785	1,13	2,99%
Feb-12	39,25	37,52	38,385	1,13	2,94%
Jan-12	38,46	35,39	36,924	0,98	2,65%
Dec-11	38,17	34,72	36,445	0,98	2,69%
Nov-11	36,89	34,06	35,475	0,98	2,76%
Average					**2,81%**

Fortis Inc.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	34,35	31,88	33,115	1,2	3,62%
Mar-12	33,17	31,70	32,435	1,2	3,70%
Feb-12	34,32	31,76	33,04	1,2	3,63%
Jan-12	33,67	32,66	33,165	1,16	3,50%
Dec-11	33,63	31,97	32,8	1,16	3,54%
Nov-11	34,16	31,32	32,74	1,16	3,54%
Average					**3,59%**

TransCanada Corp.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	43,80	42,10	42,95	1,76	4,10%
Mar-12	44,60	42,31	43,455	1,76	4,05%
Feb-12	43,69	41,02	42,355	1,68	3,97%
Jan-12	44,75	40,34	42,545	1,68	3,95%
Dec-11	44,74	42,03	43,385	1,68	3,87%
Nov-11	42,90	39,24	41,07	1,68	4,09%
Average					**4,00%**

Source: Bloomberg, As of April, 2012

Intragaz Limited Partnership

U.S. Natural Gas Pipeline & Storage Proxy Companies
Dividend Yields
November 2011 - April 2012

	Symbol	Yield
Boardwalk Pipeline Partners, LP	BWP	7,77%
Spectra Energy Corp	SE	3,67%
Spectra Energy Partners, LP	SEP	6,01%
TC Pipelines, LP	TCP	6,70%
Williams Partners L.P.	WPZ	5,11%

Average	5,85%
Median	6,01%

Boardwalk Pipeline Partners LP	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	27,68	26,01	26,845	2,12	7,90%
Mar-12	27,94	26,09	27,015	2,12	7,85%
Feb-12	27,62	26,51	27,065	2,12	7,83%
Jan-12	29,43	27,10	28,265	2,11	7,47%
Dec-11	28,21	25,85	27,03	2,11	7,81%
Nov-11	28,75	25,38	27,065	2,11	7,80%
Average					**7,77%**

Spectra Energy	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	31,79	29,77	30,78	1,12	3,64%
Mar-12	32,27	30,83	31,55	1,12	3,55%
Feb-12	31,91	30,25	31,08	1,12	3,60%
Jan-12	31,98	30,17	31,075	1,12	3,60%
Dec-11	31,33	28,85	30,09	1,12	3,72%
Nov-11	29,83	27,53	28,68	1,12	3,91%
Average					**3,67%**

Intragaz Limited Partnership

U.S. Natural Gas Pipeline & Storage Proxy Companies
Dividend Yields
November 2011 - April 2012

Spectra Energy Partners, L. P.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	32,50	31,00	31,75	1,9	5,98%
Mar-12	33,13	31,00	32,065	1,9	5,93%
Feb-12	33,26	31,10	32,18	1,9	5,90%
Jan-12	33,27	31,20	32,235	1,9	5,89%
Dec-11	32,00	29,82	30,91	1,88	6,08%
Nov-11	31,01	28,98	29,995	1,88	6,27%
Average					**6,01%**

TC PipeLines L.P.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	45,43	42,60	44,01275	3,08	7,00%
Mar-12	46,88	44,27	45,5755	3,08	6,76%
Feb-12	47,30	45,26	46,28	3,08	6,66%
Jan-12	47,75	45,75	46,75	3,08	6,59%
Dec-11	48,30	46,41	47,355	3,08	6,50%
Nov-11	47,72	44,56	46,14	3,08	6,68%
Average					**6,70%**

Williams Partners L.P.	High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
Apr-12	57,75	53,35	55,55	3,05	5,49%
Mar-12	62,42	55,02	58,72	3,05	5,19%
Feb-12	62,35	60,57	61,46	3,05	4,96%
Jan-12	65,40	60,51	62,9525	2,99	4,75%
Dec-11	61,22	57,45	59,335	2,99	5,04%
Nov-11	59,28	55,75	57,515	2,99	5,20%
Average					**5,11%**

Source: Bloomberg, As of April 30, 2012

Intragaz Limited Partnership

Canadian Utility Proxy Companies
Growth Rate Forecasts

Corporations	Ticker	SNL Long-Term Growth
Canadian Utilities Limited	CU	6,20%
Emera Inc.	EMA	7,10%
Enbridge Inc.	ENB	10,00%
Fortis Inc.	FTS	4,60%
TransCanada Corporation	TRP	7,40%
Average		7,06%
Median		7,10%

Source: SNL Interactive

Intragaz Limited Partnership

U.S. Natural Gas Pipeline & Storage Proxy Companies
Growth Rate Forecasts

MLPs	Ticker	SNL Long-Term Growth
Boardwalk Pipeline Partners, LP	BWP	2,00%
Spectra Energy Partners, LP	SEP	3,50%
TC Pipelines, LP	TCP	4,00%
Williams Partners L.P.	WPZ	7,00%

Corporations	Ticker	SNL Long-Term Growth
Spectra Energy Corp	SE	7,90%
Average		4,88%
Median		4,00%

Source: SNL Interactive

Intragaz Limited Partnership
Canadian Utility Companies
DCF Results

Line No.		Ticker	Dividend Yield	Dividend Yield Times (1 + .50g)	Expected Growth Rate (g)	Secondary Market[1]: Investor Required Return	Flotation Cost Adjustment	Primary Market[2]: Cost of Capital
		[A]	[B]	[C]	[D]	[E]	[F]	[G]
1	Canadian Utilities Limited	CU	2,67%	2,75%	6,20%	8,95%	1,040	9,31%
2	Emera Inc.	EMA	4,08%	4,23%	7,10%	11,33%	1,040	11,78%
3	Enbridge Inc.	ENB	2,81%	2,95%	10,00%	12,95%	1,040	13,47%
4	Fortis Inc.	FTS	3,59%	3,67%	4,60%	8,27%	1,040	8,60%
5	TransCanada Corporation	TRP	4,00%	4,15%	7,40%	11,55%	1,040	12,01%
6	High					12,95%		13,47%
7	3rd Quartile					11,55%		12,01%
8	**2nd Quartile (Median)**					**11,33%**		**11,78%**
9	1st Quartile					8,95%		9,31%
10	Low					8,27%		8,60%

[1] Return required by investors when they trade stocks in the "secondary" market.
[2] Cost to companies when they raise common equity capital in the "primary" market.

[B] See Schedule 5 p 1 of 2
[C] = Col [B] x (1+ .5 Col [D])
[D] See Schedule 6 p 1 of 2
[E] = Col [C] + Col [D]
[F] See Schedule 8
[G] = Col [E] x Col [F]

Intragaz Limited Partnership
U.S. Natural Gas Pipeline & Storage Proxy Companies
DCF Results

		[A]	[B]	[C]	[D]	[E]	[F]	[G]
						Secondary Market[1]:		**Primary Market[2]:**
Line No.		**Ticker**	**Dividend Yield**	**Dividend Yield Times (1 + .50g)**	**Expected Growth Rate (g)**	**Investor Required Return**	**Flotation Cost Adjustment**	**Cost of Capital**
1	Boardwalk Pipeline Partners, LP	BWP	7,77%	7,85%	2,00%	9,85%	1,040	10,25%
2	Spectra Energy Corp	SE	3,67%	3,82%	7,90%	11,72%	1,040	12,18%
3	Spectra Energy Partners, LP	SEP	6,01%	6,11%	3,50%	9,61%	1,040	10,00%
4	TC Pipelines, LP	TCP	6,70%	6,83%	4,00%	10,83%	1,040	11,26%
5	Williams Partners L.P.	WPZ	5,11%	5,28%	7,00%	12,28%	1,040	12,78%
6	High					12,28%		12,78%
7	3rd Quartile					11,72%		12,18%
8	**2nd Quartile (Median)**					**10,83%**		**11,26%**
9	1st Quartile					9,85%		10,25%
10	Low					9,61%		10,00%

[1] Return required by investors when they trade stocks in the "secondary" market.
[2] Cost to companies when they raise common equity capital in the "primary" market.

[B] See Schedule 5 p 2 of 2
[C] = Col [B] x (1+ .5 Col [D])
[D] See Schedule 6 p 2 of 2
[E] = Col [C] + Col [D]
[F] See Schedule 8
[G] = Col [E] x Col [F]

Intragaz Limited Partnership

Common Equity Flotation Costs of
Natural Gas Distribution/Transmission/Storage Companies
2000-2011

	[A]	[B]	[C]	[D]	[E]
Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Semco	2000-06-12	9 000 000	$10,000	$9,600	4,17%
WGL Holdings	2001-06-26	1 790 000	$26,730	$25,804	3,59%
Utilicorp	2002-01-25	11 000 000	$23,000	$22,252	3,36%
Enbridge Energy Partners L.P.	2002-02-27	2 200 000	$42,750	$40,933	4,44%
NUI Corporation	2002-03-14	1 500 000	$22,500	$21,430	4,99%
GulfTerra Energy Partners L.P.	2002-04-24	3 000 000	$37,860	$36,251	4,44%
Markwest Energy Partners L.P.	2002-05-20	2 100 000	$20,500	$19,065	7,53%
ONEOK Partners L.P.	2002-06-13	1 280 000	$35,970	$34,610	3,93%
El Paso Corporation	2002-06-20	45 000 000	$19,950	$19,350	3,10%
ONEOK Partners L.P.	2002-06-27	2 000 000	$35,500	$33,990	4,44%
Kinder Morgan Management LLC	2002-07-31	12 000 000	$27,500	$26,540	3,62%
Enterprise Products Partners	2002-10-03	9 800 000	$18,990	$18,180	4,46%
Enbridge Energy Management L	2002-10-10	9 000 000	$39,000	$37,050	5,26%
NiSource Inc.	2002-11-06	36 000 000	$18,300	$17,751	3,09%
MDU Resources Group	2002-11-29	2 100 000	$24,000	$23,188	3,50%
Enterprise Products Partners	2003-01-09	12 750 000	$18,010	$17,245	4,44%
KeySpan Corporation	2003-01-14	13 900 000	$34,500	$34,070	1,26%
ONEOK Inc.	2003-01-23	12 000 000	$17,190	$16,524	4,03%
AGL Resources Inc.	2003-02-11	5 600 000	$22,000	$21,230	3,63%
GulfTerra Energy Partners L.P.	2003-04-08	3 000 000	$31,350	$30,018	4,44%
Delta Natural Gas Company Inc.	2003-04-29	530 000	$21,600	$20,650	4,60%
Atlas Pipeline Partners L.P.	2003-05-05	950 000	$25,000	$23,375	6,95%
Enbridge Energy Partners L.P.	2003-05-06	3 350 000	$44,790	$42,886	4,44%
Energy Transfer Partners L.P.	2003-05-13	1 400 000	$29,260	$27,797	5,26%
ONEOK Partners L.P.	2003-05-20	2 250 000	$40,500	$38,779	4,44%
Kinder Morgan Energy Partners	2003-05-28	4 000 000	$39,350	$37,680	4,43%
Enterprise Products Partners	2003-05-29	10 400 000	$22,350	$21,400	4,44%
Southern Union Company	2003-06-05	9 500 000	$16,000	$15,440	3,63%
Atmos Energy Corporation	2003-06-18	4 000 000	$25,310	$24,298	4,16%
GulfTerra Energy Partners L.P.	2003-06-19	1 000 000	$36,500	$35,222	3,63%
ONEOK Inc.	2003-08-05	9 500 000	$19,000	$18,620	2,04%
Vectren Corporation	2003-08-07	6 500 000	$22,810	$22,012	3,63%
Sempra Energy	2003-10-08	15 000 000	$28,000	$27,160	3,09%
GulfTerra Energy Partners	2003-10-15	4 800 000	$40,600	$38,874	4,44%
Unitil Corporation	2003-10-23	624 000	$25,400	$24,130	5,26%
El Paso Corporation	2003-11-19	8 790 000	$5,950	$5,900	0,85%
Enbridge Energy Partners L.P.	2003-12-03	5 000 000	$50,300	$48,162	4,44%
El Paso Corporation	2003-12-23	8 790 000	$7,850	$7,745	1,36%
El Paso Corporation	2004-01-05	8 790 000	$8,350	$8,250	1,21%
Markwest Energy Partners L.P.	2004-01-12	1 150 000	$39,900	$37,805	5,54%
Energy Transfer Partners L.P.	2004-01-13	8 000 000	$38,690	$36,560	5,83%
Piedmont Natural Gas Company	2004-01-20	4 250 000	$42,500	$41,010	3,63%
Kinder Morgan Energy Partners	2004-02-04	5 300 000	$46,800	$44,869	4,30%
ONEOK Inc.	2004-02-05	6 900 000	$22,000	$21,930	0,32%
UGI Corporation	2004-03-18	7 500 000	$32,100	$30,696	4,57%
Northwest Natural Gas Company	2004-03-30	1 200 000	$31,000	$29,990	3,37%
Enterprise Products Partners	2004-04-29	15 000 000	$21,000	$20,107	4,44%
The Laclede Group	2004-05-25	1 500 000	$26,800	$25,929	3,36%
Energy Transfer Partners L.P.	2004-06-24	4 500 000	$39,200	$37,534	4,44%
Atmos Energy Corporation	2004-07-13	8 650 000	$24,750	$23,760	4,17%
Southern Union Company	2004-07-26	11 000 000	$18,750	$18,094	3,63%
Enterprise Products Partners	2004-08-04	15 000 000	$20,200	$19,341	4,44%

Intragaz Limited Partnership

Common Equity Flotation Costs of
Natural Gas Distribution/Transmission/Storage Companies
2000-2011

	[A]	[B]	[C]	[D]	[E]
Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Enbridge Energy Partners L.P.	2004-09-09	3 200 000	$47,900	$45,864	4,44%
Markwest Energy Partners L.P.	2004-09-15	2 160 000	$43,410	$41,350	4,98%
Atmos Energy Corporation	2004-10-21	14 000 000	$24,750	$23,760	4,17%
Kinder Morgan Energy Partners	2004-11-04	5 500 000	$46,000	$44,160	4,17%
AGL Resources Inc.	2004-11-18	9 600 000	$31,010	$30,080	3,09%
Southern Union Company	2005-02-07	14 910 000	$23,000	$22,300	3,14%
Enterprise Products Partners	2005-02-11	15 000 000	$27,050	$25,968	4,17%
TC Pipelines L.P.	2005-03-17	3 500 000	$37,040	$35,470	4,43%
Kinder Morgan Energy Partners	2005-08-10	5 000 000	$51,250	$49,330	3,89%
Semco Energy Inc.	2005-08-10	4 300 000	$6,320	$6,067	4,17%
Williams Partners L.P.	2005-08-17	5 000 000	$21,500	$20,130	6,81%
Enterprise GP Holdings L.P.	2005-08-23	12 600 000	$28,000	$26,320	6,38%
Kinder Morgan Energy Partners	2005-11-02	2 600 000	$51,750	$50,051	3,39%
Boardwalk Pipeline Partners	2005-11-08	15 000 000	$19,500	$18,330	6,38%
Enbridge Energy Partners L.P.	2005-11-16	3 000 000	$46,000	$44,160	4,17%
Enterprise Products Partners	2005-11-29	4 000 000	$25,030	$24,520	2,08%
Kinder Morgan Management	2005-12-21	1 670 000	$45,000	$44,430	1,28%
Regency Energy Partners L.P.	2006-01-31	13 750 000	$20,000	$18,787	6,46%
Energy Transfer Equity L.P.	2006-02-02	21 000 000	$21,000	$19,792	6,10%
Enterprise Products Partners	2006-03-02	16 000 000	$23,900	$22,944	4,17%
El Paso Corporation	2006-05-23	35 700 000	$14,150	$14,025	0,89%
Williams Partners L.P.	2006-06-14	6 600 000	$31,250	$29,922	4,44%
Markwest Energy Partners L.P.	2006-06-30	3 000 000	$39,750	$37,961	4,71%
Kinder Morgan Energy Partners	2006-08-09	5 000 000	$44,800	$43,132	3,87%
Enterprise Products Partners	2006-09-07	11 000 000	$25,800	$24,839	3,87%
Boardwalk Pipeline Partners	2006-11-16	6 000 000	$29,650	$28,390	4,44%
Chesapeake Utilities Corporation	2006-11-16	600 000	$30,100	$28,975	3,88%
Williams Partners L.P.	2006-12-06	7 000 000	$38,000	$36,480	4,17%
Atmos Energy Corporation	2006-12-07	5 500 000	$31,500	$30,397	3,63%
Vectren Corportation	2007-02-22	4 600 000	$28,330	$27,338	3,63%
Boardwalk Pipeline Partners	2007-03-19	8 000 000	$36,500	$36,000	1,39%
Enterprise Products Partners	2007-04-13	13 500 000	$31,250	$30,620	2,06%
Enbridge Energy Partners L.P.	2007-05-16	5 300 000	$58,000	$57,040	1,68%
Spectra Energy Partners L.P.	2007-06-26	10 000 000	$22,000	$20,625	6,67%
Regency Energy Partners L.P.	2007-07-26	10 000 000	$32,050	$30,768	4,17%
Boardwalk Pipeline Partners	2007-11-02	7 500 000	$30,900	$30,420	1,58%
Energy Transfer Equity L.P.	2007-11-07	7 340 000	$31,700	$30,432	4,17%
El Paso Pipeline Partners L.P.	2007-11-15	25 000 000	$20,000	$18,800	6,38%
Kinder Morgan Energy Partners	2007-11-30	6 200 000	$49,340	$48,090	2,60%
Williams Partners L.P.	2007-12-05	9 250 000	$37,750	$36,240	4,17%
Energy Transfer Partners L.P.	2007-12-13	5 000 000	$48,810	$46,858	4,17%
Williams Pipeline Partners L.P.	2008-01-17	16 250 000	$20,000	$18,800	6,38%
Enbridge Energy Partners L.P.	2008-02-27	4 000 000	$49,000	$47,285	3,63%
Kinder Morgan Energy Partners	2008-02-27	5 000 000	$57,700	$56,380	2,34%
ONEOK Partners L.P.	2008-03-11	2 500 000	$58,100	$56,150	3,47%
Markwest Energy Partners L.P.	2008-04-08	5 000 000	$31,150	$29,904	4,17%
EQT Corp	2008-05-06	7 500 000	$67,750	$65,040	4,17%
Western Gas Partners L.P.	2008-05-08	18 750 000	$16,500	$15,510	6,38%
Boardwalk Pipeline Partners	2008-06-10	10 000 000	$25,300	$24,352	3,89%
Energy Transfer Partners L.P.	2008-07-15	7 750 000	$39,450	$37,872	4,17%
Regency Energy Partners L.P.	2008-09-11	7 100 000	$21,000	$20,210	3,91%
Teppco Partners	2008-09-04	8 000 000	$29,000	$27,985	3,63%
Regency Energy Partners	2008-09-11	7 100 000	$21,000	$20,210	3,91%

Intragaz Limited Partnership

Common Equity Flotation Costs of Natural Gas Distribution/Transmission/Storage Companies 2000-2011

	[A]	[B]	[C]	[D]	[E]
Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Unitil Corporation	2008-12-15	2 270 000	$20,000	$18,181	10,00%
Kinder Morgan Energy Partners	2008-12-17	3 900 000	$46,750	$45,290	3,22%
Enterprise Products Partners	2009-01-07	9 600 000	$22,200	$21,330	4,08%
Energy Transfer Partners	2009-01-22	6 000 000	$34,050	$32,660	4,26%
Spectra Energy Partners	2009-02-10	28 000 000	$14,350	$13,919	3,10%
Kinder Morgan Energy Partners	2009-02-26	5 500 000	$46,950	$45,530	3,12%
Energy Transfer Partners	2009-04-15	8 500 000	$37,550	$36,048	4,17%
Spectra Energy Partners	2009-05-20	9 000 000	$22,000	$21,120	4,17%
Unitil Corporation	2009-05-27	2 700 000	$20,000	$18,614	7,45%
Markwest Energy Partners	2009-06-05	2 900 000	$18,150	$17,352	4,60%
El Paso Pipeline Partners	2009-06-09	11 000 000	$17,500	$16,800	4,17%
Kinder Morgan Energy Partners	2009-06-09	5 750 000	$51,500	$49,900	3,21%
Oneok Partners LP	2009-06-16	5 000 000	$45,810	$43,980	4,16%
Boardwalk Pipeline Partners	2009-08-11	7 250 000	$23,000	$22,150	3,84%
Markwest Energy Partners	2009-08-13	5 500 000	$20,950	$20,066	4,41%
Centerppoint Energy Inc	2009-09-10	21 000 000	$12,000	$11,580	3,63%
Energy Transfer Partners	2009-10-01	6 000 000	$41,270	$39,997	3,18%
TC Pipelines	2009-11-13	5 000 000	$38,000	$36,420	4,34%
DCP Midstream Partners	2009-11-19	2 500 000	$25,400	$24,340	4,35%
Kinder Morgan Energy Partners	2009-12-01	4 500 000	$57,150	$55,350	3,25%
Regency Energy Partners	2009-12-02	10 500 000	$19,120	$18,270	4,65%
Western Gas Partners	2009-12-04	6 000 000	$18,200	$17,460	4,24%
Energy Transfer Partners	2010-01-06	8 500 000	$44,720	$43,330	3,21%
Enterprise Products Partners	2010-01-07	9 500 000	$32,420	$31,430	3,15%
El Paso Pipeline Partners	2010-01-13	8 750 000	$24,480	$23,460	4,35%
Oneok Partners LP	2010-02-02	5 250 000	$60,750	$58,720	3,46%
Boardwalk Pipeline Partners	2010-02-18	10 000 000	$30,020	$28,930	3,77%
EQT Corp	2010-03-10	12 500 000	$44,000	$42,240	4,17%
Enterprise Products Partners	2010-04-13	12 000 000	$35,550	$34,480	3,10%
Kinder Morgan Energy Partners LP	2010-05-04	6 500 000	$66,250	$64,220	3,16%
Niska Gas Storage Partners LLC	2010-05-11	17 500 000	$20,500	$19,244	6,52%
Western Gas Partners LP	2010-05-13	4 000 000	$22,250	$21,350	4,22%
CenterPoint Energy Inc	2010-06-09	22 000 000	$12,900	$12,448	3,63%
El Paso Pipeline Partners LP	2010-06-18	10 000 000	$28,800	$27,690	4,01%
Energy Transfer Partners LP	2010-08-18	9 500 000	$46,220	$44,798	3,17%
NiSource Inc	2010-09-08	21 100 000	$16,500	$15,964	3,36%
El Paso Pipeline Partners LP	2010-09-15	11 500 000	$31,950	$30,774	3,82%
Williams Partners LP	2010-09-23	9 250 000	$42,400	$41,110	3,14%
Western Gas Partners LP	2010-11-09	7 500 000	$29,920	$28,730	4,14%
Enbridge Energy Partners LP	2010-11-10	5 200 000	$60,120	$58,180	3,33%
Gas Natural Inc	2010-11-10	2 100 000	$10,000	$9,400	6,38%
El Paso Pipeline Partners LP	2010-11-16	10 500 000	$33,450	$32,330	3,46%
Enterprise Products Partners LP	2010-12-01	11 500 000	$41,250	$39,976	3,19%
Spectra Energy Partners LP	2010-12-02	6 250 000	$32,870	$31,550	4,18%
Williams Partners LP	2010-12-14	8 000 000	$47,550	$46,110	3,12%
MarkWest Energy Partners LP	2011-01-11	3 000 000	$41,200	$40,130	2,67%
Kinder Morgan Inc/Delaware	2011-02-10	95 466 600	$30,000	$29,100	3,09%
Western Gas Partners LP	2011-03-01	3 550 000	$35,150	$33,750	4,15%
DCP Midstream Partners LP	2011-03-04	3 200 000	$40,550	$38,920	4,19%
El Paso Pipeline Partners LP	2011-03-09	12 000 000	$34,300	$33,150	3,47%
Energy Transfer Partners LP	2011-03-29	12 350 000	$50,520	$48,980	3,14%
TC Pipelines LP	2011-04-28	6 300 000	$47,580	$45,670	4,18%
El Paso Pipeline Partners LP	2011-05-13	14 000 000	$34,510	$33,350	3,48%

Intragaz Limited Partnership

Common Equity Flotation Costs of Natural Gas Distribution/Transmission/Storage Companies 2000-2011

	[A]	[B]	[C]	[D]	[E]
Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Boardwalk Pipeline Partners LP	2011-05-27	6 000 000	$29,330	$28,370	3,38%
Spectra Energy Partners LP	2011-06-08	6 250 000	$30,960	$29,720	4,17%
Kinder Morgan Energy Partners LP	2011-06-14	6 700 000	$71,440	$69,290	3,10%
Enbridge Energy Partners LP	2011-06-28	7 000 000	$30,000	$29,090	3,13%
MarkWest Energy Partners LP	2011-07-08	3 500 000	$48,000	$46,070	4,19%
American Midstream Partners LP	2011-07-26	3 750 000	$21,000	$19,688	6,67%
Cheniere Energy Partners LP	2011-09-14	3 000 000	$15,250	$14,550	4,81%
Western Gas Partners LP	2011-09-20	5 000 000	$35,860	$34,560	3,76%
Enbridge Energy Partners LP	2011-09-22	8 000 000	$28,200	$27,350	3,11%
Regency Energy Partners LP	2011-10-07	10 000 000	$20,920	$20,200	3,56%
Energy Transfer Partners LP	2011-11-08	13 250 000	$44,670	$43,330	3,09%
Enbridge Energy Partners LP	2011-12-02	8 500 000	$30,850	$29,910	3,14%
Enterprise Products Partners LP	2011-12-08	9 000 000	$44,680	$43,340	3,09%
MarkWest Energy Partners LP	2011-12-13	10 000 000	$54,250	$52,134	4,06%
Inergy Midstream LP	2011-12-15	16 000 000	$17,000	$15,980	6,38%
Average 2000-2011					**3,96%**
Selected Flotation Costs for Cost of Equity					**4,00%**

Sources: EBASCO, *Analysis of Public Utility Financing* and *Public Utility Financing Tracker, Edgar Online, Bloomberg*

Intragaz Limited Partnership

Canadian Utility Companies
Capital Structures as of December 31, 2011

		[A]	[B]	[C]	[D]	[E]	[F]	[G]
		Debt	%	Preferred Stock	%	Equity	%	Total Capital
Line No.		(Thousands)		(Thousands)		(Thousands)		
1	Canadian Utilities Limited	$ 4 730 000	53,05%	$ 724 000	8,12%	$ 3 462 000	38,83%	$ 8 916 000
2	Emera Inc.	$ 3 519 500	65,87%	$ 146 700	2,75%	$ 1 677 000	31,39%	$ 5 343 200
3	Enbridge Inc.	$ 20 153 000	65,50%	$ 1 056 000	3,43%	$ 9 559 000	31,07%	$ 30 768 000
4	Fortis Inc.	$ 6 264 000	57,25%	$ 592 000	5,41%	$ 4 085 000	37,34%	$ 10 941 000
5	TransCanada Corporation	$ 22 278 000	54,25%	$ 1 224 000	2,98%	$ 17 565 000	42,77%	$ 41 067 000
6	Mean		59,18%		4,54%		36,28%	
7	Median		57,25%		3,43%		37,34%	

Source: SNL Financial

Intragaz Limited Partnership

U.S. Pipeline and Storage Proxy Companies
Capital Structures as of December 31, 2011

Line No.		[A] Debt (Thousands)	[B] %	[C] Preferred Stock (Thousands)	[D] %	[E] Equity (Thousands)	[F] %	[G] Total Capital
1	Boardwalk Pipeline Partners, LP	$ 3 198 700	49,95%	$ -	0,00%	$ 3 205 200	50,05%	$ 6 403 900
2	Spectra Energy Corp	$ 11 723 000	56,15%	$ 258 000	1,24%	$ 8 896 000	42,61%	$ 20 877 000
3	Spectra Energy Partners, LP	$ 706 900	29,40%	$ -	0,00%	$ 1 697 700	70,60%	$ 2 404 600
4	TC Pipelines, LP	$ 742 500	35,77%	$ -	0,00%	$ 1 333 000	64,23%	$ 2 075 500
5	Williams Partners L.P.	$ 7 237 000	58,06%	$ -	0,00%	$ 5 228 000	41,94%	$ 12 465 000
6	Mean		45,87%		0,25%		53,89%	
7	Median		49,95%		0,00%		50,05%	

Source: 2011 10-Ks

Intragaz Limited Partnership

CALCULATION OF MEDIAN RESULTS

		Discounted Cash Flow (DCF)		Source
		Canadian Utility Proxy Group	U.S. Pipeline & Storage Proxy Group	
[1]	Dividend Yield	4,08%	6,70%	Schedule 7
[2]	x Growth Adj. Factor	1,036	1,020	Equals 1 + (0.5 x [4])
[3]	Expected Dividend Yield	**4,23%**	**6,83%**	Equals [1] x [2]
[4]	+ Expected Growth Rate	**7,10%**	**4,00%**	Schedule 7
[5]	Secondary Market ROE	**11,33%**	**10,83%**	Equals [3] + [4]
[6]	x Flotation Cost Adj.	1,04	1,04	Schedule 8
[7]	Primary Market ROE	**11,78%**	**11,26%**	Equals [5] x [6]