uniongas

July 18, 2012

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

RE: EB-2011-0210 – Union Gas Limited – 2013 Rates Application

Dear Ms. Walli,

Please find attached Union Gas Limited's ("Union") cross-examination material for Dr. Booth.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

CC: EB-2011-0210 Intervenors
Crawford Smith (Torys)

EB-2011-0210

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act*, 1998, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

UNION GAS LIMITED

("Union")

CROSS-EXAMINATION COMPENDIUM

COST OF CAPITAL

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 4

DATE: July 16, 2012

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

test year be established using the formula as determined in the 'Report of the Board on the Cost of Capital for Ontario's Regulated Utilities' dated December 11, 2009 (EB-2009-0084). The Board's findings in the Report maintain a formulaic approach to setting ROE levels. However, the formula (originally established in the Board's 'Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities' released in March 1997) was reset primarily to address relatively low ROE levels as well as to reduce its sensitivity to changes in government bond yields."

That's what you say in your testimony?

MR. BROEDERS: That's correct.

MR. THOMPSON: So am I correct that Union is seeking a return on equity in accordance with the Board's report?

MR. BROEDERS: Yes.

MR. THOMPSON: Now, am I also correct that Union is not requesting any review or reversal of any of the components of that report?

MR. BROEDERS: That's correct.

MR. THOMPSON: Now, the methodology reflected in the report -- I am suggesting to you the methodology reflected in the report is the method where decisions regarding the cost of equity and capital structure are made separately. Do you agree that that is the methodology reflected in the report?

MR. BROEDERS: I believe so, yes.

MR. THOMPSON: Thank you. And am I correct that Union is not relying on any method, other than the methodology set out in the report, to support its request for an increase in its common equity ratio from 36 percent to 40 percent?

MR. BROEDERS: There is not a methodology within that report to indicate how you calculate a proper equity structure.

MR. THOMPSON: Sorry, that wasn't my question.

Are you relying on a methodology other than what's specified in that report?

MR. BROEDERS: There isn't a methodology specified in that report.

MR. THOMPSON: All right. Well, let's follow up on that, then, if we might.

The report -- do you have the copy of the report there with you?

MR. BROEDERS: I don't think I have a copy with me, no.

MR. THOMPSON: Okay. Well, I think the portion of the report that I want to refer to is part of Mr. Aiken's initial compendium. I think it's K1.1. I don't have that in front of me, but it's the -- the portion is --

MR. BROEDERS: Sorry, there was a compendium by Mr. Aiken?

MR. THOMPSON: Aiken, yes. Exhibit K1.1, I believe.

MR. BROEDERS: Oh.

Appendix A

Joseph L. Rotman School of Management
University of Toronto

Professor Laurence Booth
CIT Chair in Structured Finance

Rotman

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TEACHING AND RESEARCH INTERESTS. Main interest is teaching domestic and international corporate finance. Research interests centre on the cost of capital, empirical corporate finance and capital market theory.

ACADEMIC BACKGROUND:

D.B.A.,	Indiana University, (finance major).
M.B.A.,	Indiana University, (finance major).
M.A.,	Indiana University, (Economics).
B. Sc.(Econ),	London School of Economics.

AWARDS & HONOURS

MBA Second Year Instructor of the Year Award, 1996, 1998 (joint) & 2000
Best paper in corporate finance, 1999 SFA meetings
ASAC Distinguished Professor Address 1990,
Director Financial Management Association 1988-90,
English Speaking Union Fellow,
Fulbright,
Elected to Beta Gamma Sigma,
First class honours B.Sc.(Econ)
CBV (Chartered Business Valuator),
National Post Leader in Management Education Award 2003

ACADEMIC EMPLOYMENT: CIT Chair in Structured Finance (1999-), Professor of Finance, Rotman School of Management, University of Toronto (1987-Present), Visiting Professor Nankai University (China) 1989, the Czech Management Centre (1998), visiting scholar London School of Economics (1985).

TEACHING EXPERIENCE: <u>Graduate</u> (MBA) courses on The Economics of Enterprise, the Economic Environment of Business, Business Finance, Corporate Financing, International Financial Management, Mergers & Acquisitions, Financial Management, Capital Markets & Corporate

Financing (EMBA), Financial Theory of the Firm (Ph.D), Capital Markets Workshop (Ph.D). Undergraduate courses (B.Comm) in International Business and Business Finance. Executive courses (2-5 days) on Money and Foreign Exchange Markets, Business Valuation, Financial Strategy, Equity Markets, Capital Market Innovations, Mergers & Acquisitions and Finance for Non-Financial Managers.

JOURNAL ARTICLES

"Stochastic Demand, Output and the Cost of Capital: A Clarification," Journal of Finance, 35 (June 1980),

"Capital Structure, Taxes and the Cost of Capital," Quarterly Review of Economics and Business, 20 (Autumn 1980,

"Stock Valuation Models Under Inflation," Financial Analysts Journal, (May-June 1981),

"Market Structure, Uncertainty and the Cost of Equity Capital," Journal of Banking and Finance, (May 1981),

"Capital Budgeting Frameworks for the Multinational Corporation," Journal of International Business Studies, (Fall 1982),

"Hedging and Foreign Exchange Exposure," Management International Review, (Spring 1982),

"Correct Procedures for Discounting Risky Cash Outflows," Journal of Financial and Quantitative Analysis, (June 1982),

"Total Price Uncertainty and the Theory of the Competitive Firm," Economica, (May 1983),

"Portfolio Composition and the CAPM," Journal of Economics and Business, (June 1983),

"On the Negative Risk Premium for Risk Adjusted Discount Rates," Journal of Business Finance and Accounting, (Spring 1983),

"On the Unanimity Literature and the Security Market Line Criterion," Journal of Business Finance and Accounting (Winter 1983),

"Empirical Tests of the Monetary Approach to Exchange Rate Determination," (with R. Vander Kr,aats) Journal of International Money and Finance, (December 1983),

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"The Ex-Dividend Day Behaviour of Canadian Stock Prices: Tax Changes and Clientele Effects," Journal of Finance, (June 1984) (with D. J. Johnstone),

"On the Relationship Between Time State Preference and Capital Asset Pricing Models," Financial Review (May 1984),

"Bid-Ask Spreads in the Market for Foreign Exchange," Journal of International Money and Finance (August 1984),

"An Economic Analysis of Hedging and The Canadian Accounting Treatment of Revenue Hedges," Canadian Journal of Administrative Sciences, (June 1987),

"The Dividend Tax Credit and Canadian Ownership Objectives," Canadian Journal of Economics (May 1987),

"A Note on the Demand for Labour and the Phillips curve Phenomenon," Journal of Economics and Business (July 1987) (with W. Y. Lee and J. Finkelstein),

"Adjustment to Production Uncertainty and the Theory of the Firm: A Note," Economic Inquiry (1988),

"The Deregulation of Canada's Financial System," Banking and Finance Law Review, (Jan 1989),

"Stock Returns and the Dollar," Canadian Investment Review, (Spring 1990), (With W. Rotenberg),

"Taxes, Funds Positioning and the Cost of Capital,' in R. Aggarwal (ed) Advances in Financial Planning and Forecasting, JAI Press, 1990,

"Assessing Foreign Exchange Exposure: Theory and Application Using Canadian Firms," Journal of International Financial Management and Accounting (Spring 1990) (With W. Rotenberg),

"Research in Finance at Canadian Administration and Management Faculties," Canadian Journal of Administrative Studies, (With F. Heath), (December 1990),

6

"The Influence of Production Technology on Risk and the Cost of Capital," Journal of Financial and Quantitative Analysis (March 1991),

"Evidence on Corporate Preferences For Foreign Currency Accounting Standards", Journal of International Financial Management and Accounting, (with W. Rotenberg) (Summer 1991)),

"Peoples Acquisition of Zale: An application of Valuation Principles," in Canadian Investment Banking Review, (R. Rupert, Editor), McGraw-Hill Ryerson, 1992,

"The Cost of Equity Capital of a Non-Traded Unique Entity," Canadian Journal of Administrative Sciences, (June 1993),

"Lessons From Canadian Capital Market History," Canadian Investment Review (Spring 1995),

"Making Capital Budgeting Decisions in Multinational Corporations," Managerial Finance 22-1, (1996),

"Great Lakes Forest Products" Accounting Education 5 (Winter 1996) (with Professor W. Rotenberg),

"On the Nature of Foreign Exchange Exposure" Journal of Multinational Financial Management" (Spring 1996),

"The Importance of Market to Book Ratios in Regulation," Quarterly Bulletin, National Regulatory Research Institute, Winter 1997,

"A New Model for Estimating Risk Premiums (Along with Evidence of their Decline)" Journal of Applied Corporate Finance, (Spring 1998),
"The Case Against Foreign Bonds in Canadian Fixed Income Portfolios," Canadian Investment Review, (Spring 1998),

"The CAPM, Equity Risk Premiums and the Privately Held Business," Journal of Business Valuation (1999),

"Estimating the Equity Risk Premium and Equity Costs: New Ways of Looking at Old Data," Journal of Applied Corporate Finance, (Spring 1999),

7

"Time to Pass the Old Maid," Canadian Investment Review, (Spring 1999),

"Risk and Return in Capital Markets," Canadian Treasurer 16-2, March 2000,

"What Drives Shareholder value," Canadian Treasurer 16-3, June 2000.

"Capital Structures in Developing Countries," Journal of Finance 61-1 (March 2001, pp 87-130) (with V. Aivazian, V. Maxsimovic and A. Demirgic Kunt), (abstracted in the CFA Digest-31 -3 August 2001)

"Discounting Expected Values with Parameter Uncertainty," Journal of Corporate Finance 9- 2 (Spring 2003, pp 505-519)

"Equity Risk Premiums in the US and Canada," Canadian Investment Review (Spring 2001),

"Financial Planning with Risk," Canadian Journal of Financial Planning (December 2001),

"How to Find Value when None Exists: Pitfalls in Using APV and FTE," Journal of Applied Corporate Finance (Spring 2002),

"Do Emerging Market Firms Follow Different Dividend Policies than Firms in the US: Evidence From Firms in 8 Emerging Markets," Journal of Financial Research 26-3, (September 2003, pp 371-387) (Abstracted in CFA Digest 34-1, Feb 2004) (With V. Aivazian and S. Cleary),

"Dividend Policy and the Organisation of Capital Markets, Journal of Multinational Financial Management, 13-2 (April 2003, pp 101-121 (With V. Aivazian and S. Cleary),

"What to do with Executive Stock Options," Canadian Investment Review 16-2, (Summer 2003, pp 12-18),

"Formulating Retirement Targets and the Impact of Time Horizon on Asset Allocation," Financial Services Review 13-1, (Spring 2004),

"Dividend Policy and the Role of the Contracting Environment," FSR Forum, December 2005, pp 13-22,

8

"Dividend Smoothing and Debt Ratings," Journal of Financial and Quantitative Analysis, with V. Aivazian and S. Cleary (June 2006),

"Capital Cash Flows, APV and Valuation," European Financial Management, (Spring 2007).

"What Drives Provincial-Canada Yield Spreads" Canadian Journal of Economics, (Summer 2007) with Walid Hejazi and George Georgoplous.

"Cash Flow Volatility, Financial Slack and Investment Decisions," China Finance Review 2-1, (January 2008) with Sean Cleary,

"Capital market Developments in the Post 1987 Period: A Canadian Perspective," Review of Accounting and Finance 8-2, 2009, with Sean Cleary.

"Collateral Damage," 2008, Canadian Investment Review 21-4, pp 10-17.

"The Secret of Canadian Banking: Common sense?" World Economics, September 2009

"Information Asymmetry, Dividend Status and SEO Announcement Day Returns" (with Bin Chang), Journal of Financial Research, (Spring 2011)

"Target Date Funds: Good News and Bad News," (with Bin Chang) Journal of Risk, Spring 2011, pp 1-28.

"The Influence of productivity growth on Equity market performance, Journal of Wealth Management (with Bin Chang, Walid Hejazi and Pauline Shum) (forthcoming)

"Asset Allocation and the Performance of American Target Date Funds," Rotman International Journal of Pension Management, (With Bin Chang) Fall 2011.

NON-JOURNAL PUBLICATIONS: "Financial Considerations for Providing Incentives for Private Industry and their Implications for Employment Level and Stability," (with M. J. Gordon) Technical study #2, Labour Market Development Task Force, Ministry of Supply and Services Canada, 1982.

"A Comparison of the Car Insurance Industry in Ontario with The Public Monopolies in Saskatchewan, Manitoba and British Columbia," 122 pp, in C. Osbourne (ed) Report of the Inquiry into Motor Vehicle Accident Compensation in Ontario, Ontario 1988.

"Securities Market Regulation: Institutional Ownership and Diversification;" "TSE Listing Proposals for Junior Companies," and "Discount Brokerage and the Entry of Financial Institutions." Reports submitted to the Ontario Securities Commission, July 1982, June 1983 and December 1983.

"Bank Profitability, Is It Excessive? (With M. Jensen and S. Klein), Report to the House Standing Committee on Finance, Trade and Economic Affairs, May 1982.

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"Section 1650 of the CICA Handbook: Interpreting Foreign Results Under a Flexible Accounting Standard," (With W. Rotenberg), CGA Communications, 1989.

"Liability Management in the Public Sector," Report for Ministry of Treasury and Economics, May 1990 (with P. Halpern,)

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"Regulation of Transmission and Distribution Activities of Ontario Hydro," in R. Daniels, Editor, Ontario Hydro at the Millenium: Has Monopoly=s Moment Passed? McGill-Queens University Press Fall 1996 (with P. Halpern).

"Competition and Profitability in the Financial Services Industry in Canada," in J. Mintz & J. Pesando (editors) Putting Consumers First C.D Howe Institute, 1996.

"What Drives Shareholder Value," Financial Intelligence IV-6, Federated Press , Spring 1999.

"Canada's Competitiveness over the last 20 years," Rotman Management, Spring/Summer 1999.

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"Investments, Alternative Investments and Bubbles," in Advisor's Guide to New Investment Opportunities, 2001.

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"The fundamentals of finance all business professionals should know and remember," Inside the Minds: Textbook Finance, Aspatore Books, June 2003.

"Anticipating the Big Boom," Rotman, the magazine of the Rotman School of Management, Fall 2005.

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"Asset Allocation: The Long View," in H. Evensky (Editor) Retirement Income Redesigned: Master Plans for Distribution, Bloomberg Press, Princeton, 2006.

"Loyalty in Finance," Rotman, the magazine of the Rotman School of Management, Fall 2006.

Introduction to Corporate Finance, John Wiley and Sons, 2007 (with Sean Cleary)

"Saving Capitalism from the Capitalists," Rotman, the magazine of the Rotman School of Management, Summer 2008.

"An Overview of Value Based Management," in Advanced Corporate Finance, C. Krishnamurti and S.R. Vishwanath Prentice Hall International, 2009.

Introduction to Corporate Finance, John Wiley and Sons, (2nd edition) 2010 (with Sean Cleary)

"The Cost of Equity Capital and Fair Rate of Return on Equity (ROE) for a Canadian Utility" Canadian Regulation, Gordon Kaiser (Editor) 2011.

TESTIMONY

Expert financial witness (individually & with the late Professor M.K. Berkowitz) in rate hearings for Altalink partners, ATCO Gas (South), ATCO Pipelines (South), ATCO Electric, Bell Canada, Consumers Gas, Teleglobe, Maritime T&T, Island Tel, BC Tel, AGT, Newfoundland Tel, Union Gas, Ontario Hydro, Centra Gas Ontario, NB Tel, Northwestel, Pacific Northern Gas, BC Gas, West Kootenay Power, TransCanada Pipelines, TransEnergie, Trans Mountain Pipelines, IPL, Westcoast Energy, Nova Gas Transmission, Foothills Pipeline, TQ&M, ANG, and Centra Gas Manitoba.

Other civil cases include: prudent investments in a money market fund; the use of inverse floaters; the valuation of a brick company; the purchase of a private company by a Crown corporation; the liability of an investment dealer in a deficient private offering memorandum; the role of the Crown in managing moneys placed "in trust," the motivation for differential investment decisions, the materiality of press releases and the role of event clauses in contracting.

Ph.D SUPERVISOR:

George Pink, A Dominance Analysis of Canadian Mutual Funds, 1988,

Greg Lypny, An Experimental Study of Managerial Pay and Firm Hedging Decisions, 1989,

Frank Skinner, Credit Quality Adjustments and Corporate Bond Yields, 1990,

Rui Pan, Probability Analysis of Option Strategies, 1994,

Peter Klein, Three Essays on the Capital Gains Lock-in Effect, 1996,

Guy Bellemare, Capital Market Segmentation: US -Canada, 1996,

Kevin Lam, The Pricing of Audit Services, 1997,

Sean Cleary, The Relation Between Firm Investment and Financial Slack, 1998,

Xinlei Zhao, Three Essays on Financial Markets, 2002,

Lynnette Purda, Elements of Corporate Debt Policy, 2003,

Themis Pantos, Investment Distortions in the Presence of a Sovereign Debt Overhang, 2003.

Zhao Sun, PEG ratios and Stock Returns, 2004.

Zhaoxia Xu, Dynamic Adjustment of Financial Policy, 2007

Bin Chang, Information in Financial Markets, 2008

Ambrus Kesckes, Three Essays on IPOs, 2008 (Co-chair with Jan Mahrt-Smith)

Jun Zhou, Industry Influences on Corporate Financial Policy, 2010.

CASE WRITING:

A fair rate of return for Bell Canada, 1986.
Canvend 1984, A & B, 1988.
Peoples Jewellers, 1988.
Great Lakes Forest Products A, 1989.
Inco, 1989.

Peoples acquisition of Zale, 1990.
American Can Canada, 1990.
Great Lakes Forest Products A, 1993 (with W. Rotenberg)
BC Telephone, 1993
103 Kirsten Avenue, 1994
Great Lakes Forest Products B, 1994 (with W. Rotenberg)
Mill Creek Jewellery,1995 (With E. Kirzner)
Chapters, draft 2002.
Second Cup Valuation, draft 2002.

SERVICE:

Executive Committee: 1980-2, 1989-90, 1993-4, 2001-3, 2009-10
Finance Area Co-ordinator 1987-91, 1994-2008
External Advisory Board, Health Administration Faculty, 1985-92.
Editorial Board Activities:

- Journal of Economics & Business 1982-87.
- Finance Section Editor, Canadian Journal of Administrative Sciences 1993-2005.
- Journal of Multinational Financial Management 1989-.
- Journal of International Business Studies 1992-
- Associate Editor, Multinational Finance Journal, 1995-
- Journal of Applied Finance 2003-2007

Director at large Multinational Finance Society 1998-
Co-Chair 1991 Northern Finance Association meetings.
Chair 1998 Northern Finance Association meetings
Chair 2008 MFS annual meetings.
President Multinational Finance Society, 2010-11
Programme Committee member FMA meetings, October 1993.
Programme Committee member SFA meetings November 2002.
Programme Committee member, MFS meetings 2002-10
Programme Committee Member, Global Finance Conference, 2006.
Programme Committee Member, European Financial Management 2006-2010
Programme Committee member, NFA meetings 2008-
Investments Committee, Trinity College, U of T.
Pension Committee, Governing Council University of Toronto, 2011
Special committee on the Supplementary Retirement Arrangement (SRA) University of Toronto, 2011
Frequent media commentator.

February 2012

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2009-0084

VOLUME: Consultation Process on Cost of Capital Review Stakeholder Conference

DATE: October 6, 2009

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rate parity.

You cannot take rates of return or interest rates from another country and apply them to a different currency without making adjustments. You have to take into account, at the very minimum, the depreciation or appreciation of the currency.

So I reject the Concentric report. I don't think it reflects the value of what we have done in Canada and the suffering we have gone through over the last 20 years, and the fact that, by and large, Canada has got it right in terms of macroeconomic policy, tax policy. We have got it right in terms of regulation of our utilities, and I see no reason why we would want to follow American practice. Thank you.

MR. GARNER: Thank you, Dr. Booth. So I will open the floor and for questions for Dr. Booth.

DR. BOOTH: I suppose I should have put my last overhead. I suppose that follows automatically. The ROE is working fine.

MR. GARNER: With that statement, we will open up. Are there questions for Dr. Booth? Fred.

Q&A SESSION:

MR. CASS: Good morning, Dr. Booth. I am Fred Cass and I represent Enbridge Gas Distribution.

I took you to say, during your presentation, that you are not an expert in the US, so you may have anticipated where I am going with some of my questions.

In any event, perhaps I might just confirm what I

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believe to be the case.

Would I be right in thinking that you have not been qualified as an expert in any US regulatory proceeding?

DR. BOOTH: That's correct. I have never been asked to appear and I have never sought to appear. So, as a result, I have never been qualified.

MR. CASS: So you have never actually even testified in a US regulatory proceeding?

DR. BOOTH: That's correct.

MR. CASS: So when you do make your comments about US regulation of utilities, you are not doing so as an expert in the area; right?

DR. BOOTH: That's right. That's why I qualified it by saying that my colleague, Andrew Safire, who is American and who has testified frequently in the United States, he was brought in by the Canadian Association of Petroleum Producers, in fact, to talk specifically about regulation in the United States.

MR. CASS: That's --

DR. BOOTH: Which is why I took my points from the transcript of the questioning by the panel members of the AUC of Mr. Safire.

MR. CASS: Yes. Well, that's -- I'm sorry. That's useful, because that is exactly where I was going next. You did, in your presentation, refer to the evidence given by Dr. Safire in Alberta, and it strikes me that the fact you rely on someone else's evidence for the purpose of this proceeding really is just confirmation of what you have

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already told us, that you yourself don't have the expertise in the area; right?

DR. BOOTH: What I would say, as I pointed out, there are three fundamental differences. In terms of the macroeconomy, I think I can talk about the US economy. In fact, any Canadian that is interested in capital markets has to be aware of what is going on in the United States.

Secondly, I am aware of the Standard & Poor's policies in the United States and the event risk in the United States.

So two out of three I can talk about.

In terms of the actual specifics of state regulation of utilities, I have not done a huge survey or work on that. What I have done is looked at the evidence that's been put forward by witnesses, when we have asked them to provide information on: How frequent are the rate reviews? What is the performance of allowed rates of return compared to actual rates of return?

So that is information that has come out of rate hearings, and that is not information that I have generated personally myself. It is information that I have filed as a result of information requests of US witnesses, like Ms. McShane sitting over there.

MR. CASS: It was, in particular, the third of the three areas that I was referring to that you're not an expert in. It is the impact of regulation in the United States; correct?

DR. BOOTH: That's correct.

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Commission protects us.

MR. CASS: Just as an aside, try HSBC, but that is --

DR. BOOTH: That is probably an ADR out of New York. And you can buy Royal Bank of Scotland if you want. I own RBS as well.

MR. CASS: But the US represents a particularly important market for Canadians because of its size and proximity?

DR. BOOTH: The US market is 50 percent of the world capital market. You can't ignore it. It is the elephant in the room.

MR. CASS: And there is growing economic integration between the two countries?

DR. BOOTH: Yes, we are reducing barriers. Free trade was a huge change in the structure of the Canadian industry.

MR. CASS: In fact, Canada is so close to the US and so linked that people don't think of us as being international?

DR. BOOTH: It is true that if you go to London and I pick up a copy of the Financial Times, you discover that they include all the world market indices except Canada. And I have never understood that, because the Canadian stock market is the sixth biggest in the world and the FT doesn't even mention the TSX; and yet it has a whole bunch of rinky-dink little equity markets that are way smaller than Canada.

MR. CASS: So I just wanted to compare these things

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just to a couple of things that the NEB said in the recent TQM decision, and they're very short, and just see if you agree with them, as well.

The NEB said Canadian firms are increasingly competing for capital on a global basis. I take it you agree with that, in light of what we just discussed?

DR. BOOTH: Yes.

MR. CASS: The NEB also said global financial markets have evolved significantly since 1994. I take it you agree with that?

DR. BOOTH: We're back to where we were round about 1900, where we actually had a fully integrated markets round about 1990, 1910, and then basically we disintegrated or segmented markets in response to the Great Depression and the stock market crash.

Whether or not we get similar segmentation in response to this crisis -- but I don't think it is going to happen, because the Americans nipped it in the bud before it sort of cascaded out of control. But there was a significant risk that, if the Americans hadn't done that, we would be back to protectionism and all sorts of restrictions.

MR. CASS: But that was a, yes, you agreed with what the NEB said on that?

DR. BOOTH: I agree that there is more capital market integration. I agree the capital flows around the world a lot easier than it used to. In fact, one of the problems that generated the problems in the US sub-prime was simply due to the huge amount of capital that was flowing into the

Canada where a regulated utility does not consistently earn its allowed rate of return.

And when I look across the utilities, they're all -- jurisdictions are all doing the same thing. The BCUC adds a little bit to the ROE, as well as adjusting the equity ratio. The Alberta Utilities Commission just adjusts the equity ratio.

The Régie gives all sorts of deferral accounts and protection for Gaz Mét. They all approach it in a slightly different way. The fact is the end result is Canadian utilities are pretty homogeneous. They earn their allowed rates of return and they're growing at the same sorts of allowed rates of return, and the financial parameters in the deferral accounts are there to adjust for that.

So I think the Canadian regulatory model, the overall implication is the same: Lower utility risk, get a lower cost of capital to lower the overall rates for utilities. It is a win-win. Low rates for customers, low risk for the utility, and the capital markets are able to finance that package. I don't see why that regulatory compact should be changed.

MS. McSHANE: So a Nova Scotia Power is the same risk as an AltaLink?

DR. BOOTH: I haven't looked at Nova Scotia Power. That is the one place in Canada I haven't testified, so I would defer on that. But AltaLink has got almost no risk. As you know, practically everything is passed on in monthly rates to the distributors; whereas Nova Scotia Power is

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Filed: 2012-05-04
EB-2011-0210
J.E-2-12-14a
Attachment 1

STANDARD & POOR'S

Global Credit Portal
RatingsDirect

January 5, 2012

Issuer Ranking:
U.S. Regulated Electric Utilities, Strongest To Weakest

Primary Credit Analyst:
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Secondary Contact:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

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Issuer Ranking:

U.S. Regulated Electric Utilities, Strongest To Weakest

The following list ranks all the rated companies in this industry from strongest to weakest based on rating and outlook. Companies with the same rating and outlook are further ranked by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry report card, please see "Industry Report Card: U.S. Regulated Electric Utilities Continue On Stable Trajectory," published on Sept. 30, 2011.

U.S. Regulated Electric Utilities

Company	Corporate credit rating*	Business profile	Financial profile
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate
NSTAR Electric Co.	A+/Watch Neg/A-1	Excellent	Intermediate
NSTAR	A+/Watch Neg/A-1	Excellent	Intermediate
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Intermediate
KeySpan Energy Delivery Long Island	A/Stable/--	Excellent	Intermediate
Alabama Power Co.	A/Stable/A-1	Excellent	Intermediate
Georgia Power Co.	A/Stable/A-1	Excellent	Intermediate
Mississippi Power Co.	A/Stable/A-1	Excellent	Intermediate
Gulf Power Co.	A/Stable/A-1	Excellent	Intermediate
Southern Co.	A/Stable/A-1	Excellent	Intermediate
Central Hudson Gas & Electric Corp.	A/Stable/--	Excellent	Significant
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant
Duke Energy Carolinas LLC	A-/Stable/A-2	Excellent	Significant
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant
Narragansett Electric Co.	A-/Stable/A-2	Excellent	Significant
New England Power Co.	A-/Stable/A-2	Excellent	Significant
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant
Duke Energy Indiana Inc.	A-/Stable/A-2	Excellent	Significant
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant

U.S. Regulated Electric Utilities (cont.)			
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Significant
Wisconsin Electric Power Co.	A-/Stable/A-2	Excellent	Significant
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant
PacifiCorp	A-/Stable/A-2	Excellent	Significant
Duke Energy Kentucky Inc.	A-/Stable/--	Excellent	Significant
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant
National Grid Holdings Inc.	A-/Stable/--	Excellent	Significant
National Grid USA	A-/Stable/A-2	Excellent	Significant
KeySpan Corp.	A-/Stable/A-2	Excellent	Significant
Wisconsin Energy Corp.	A-/Stable/A-2	Excellent	Significant
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant
Duke Energy Corp.	A-/Stable/A-2	Excellent	Significant
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant
Duke Energy Ohio Inc.	A-/Stable/A-2	Strong	Significant
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Watch Pos/A-2	Excellent	Aggressive
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Watch Pos/A-2	Excellent	Aggressive
Progress Energy Inc.	BBB+/Watch Pos/A-2	Excellent	Aggressive
Connecticut Light & Power Co.	BBB+/Watch Pos/--	Excellent	Aggressive
Western Massachusetts Electric Co.	BBB+/Watch Pos/--	Excellent	Aggressive
Public Service Co. of New Hampshire	BBB+/Watch Pos/--	Excellent	Aggressive
Northeast Utilities	BBB+/Watch Pos/--	Excellent	Aggressive
Interstate Power & Light Co.	BBB+/Positive/A-2	Excellent	Significant
Alliant Energy Corp.	BBB+/Positive/A-2	Excellent	Significant
Integrys Energy Group Inc.	BBB+/Positive/A-2	Strong	Significant
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Significant
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Significant
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant
Central Maine Power Co.	BBB+/Stable/--	Excellent	Aggressive
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant

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U.S. Regulated Electric Utilities (cont.)			
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant
New York State Electric & Gas Corp.	BBB+/Stable/--	Excellent	Significant
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive
CenterPoint Energy Houston Electric LLC	BBB+/Stable/--	Excellent	Aggressive
CenterPoint Energy Resources Corp.	BBB+/Stable/A-2	Excellent	Aggressive
CenterPoint Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Significant
Detroit Edison Co.	BBB+/Stable/A-2	Strong	Significant
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant
Montana-Dakota Utilities Co.	BBB+/Stable/--	Strong	Intermediate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Significant
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant
Arizona Public Service Co.	BBB/Positive/A-2	Excellent	Aggressive
Pinnacle West Capital Corp.	BBB/Positive/A-2	Excellent	Aggressive
Rochester Gas & Electric Corp.	BBB/Positive/--	Excellent	Aggressive
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant
PG&E Corp.	BBB/Stable/--	Strong	Significant
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive
United Illuminating Co. (The)	BBB/Stable/--	Excellent	Aggressive
Columbus Southern Power Co.	BBB/Stable/--	Excellent	Aggressive
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive
KCP&L Greater Missouri Operations Co.	BBB/Stable/A-2	Excellent	Aggressive
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive

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U.S. Regulated Electric Utilities (cont.)			
Cleco Power LLC	BBB/Stable/--	Excellent	Aggressive
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive
PPL Corp.	BBB/Stable/--	Excellent	Aggressive
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive
Cleco Corp.	BBB/Stable/--	Excellent	Aggressive
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive
Entergy Gulf States Louisiana LLC	BBB/Negative/--	Excellent	Significant
Entergy Louisiana LLC	BBB/Negative/--	Excellent	Significant
Entergy Mississippi Inc.	BBB/Negative/--	Excellent	Significant
Entergy Arkansas Inc.	BBB/Negative/--	Excellent	Significant
Entergy Texas Inc.	BBB/Negative/--	Excellent	Significant
Entergy New Orleans Inc.	BBB/Negative/--	Excellent	Significant
System Energy Resources Inc.	BBB/Negative/--	Excellent	Significant
Entergy Corp.	BBB/Negative/--	Strong	Significant
Ameren Illinois Co.	BBB-/Positive/A-3	Excellent	Significant
Ameren Missouri	BBB-/Positive/A-3	Excellent	Significant
Ameren Corp.	BBB-/Positive/A-3	Strong	Significant
American Transmission Systems Inc.	BBB-/Stable/--	Excellent	Aggressive
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive
Duquesne Light Holdings Inc.	BBB-/Stable/--	Excellent	Aggressive
Indianapolis Power & Light Co.	BBB-/Stable/--	Excellent	Highly leveraged
IPALCO Enterprises Inc.	BBB-/Stable/--	Excellent	Highly leveraged
Consumers Energy Co.	BBB-/Stable/--	Excellent	Aggressive
CMS Energy Corp.	BBB-/Stable/A-3	Excellent	Aggressive
Black Hills Power Inc.	BBB-/Stable/--	Excellent	Aggressive
Otter Tail Power Co.	BBB-/Stable/--	Excellent	Significant

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U.S. Regulated Electric Utilities (cont.)			
Empire District Electric Co.	BBB-/Stable/A-3	Excellent	Aggressive
Northern Indiana Public Service Co.	BBB-/Stable/--	Excellent	Aggressive
Dayton Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive
DPL Inc.	BBB-/Stable/--	Excellent	Aggressive
Hawaiian Electric Co. Inc.	BBB-/Stable/A-3	Strong	Aggressive
Edison International	BBB-/Stable/--	Strong	Aggressive
FirstEnergy Corp.	BBB-/Stable/--	Strong	Aggressive
Black Hills Corp.	BBB-/Stable/--	Strong	Aggressive
Hawaiian Electric Industries Inc.	BBB-/Stable/A-3	Strong	Aggressive
Ohio Valley Electric Corp.	BBB-/Stable/--	Strong	Aggressive
Otter Tail Corp.	BBB-/Stable/--	Satisfactory	Significant
Nevada Power Co.	BB+/Stable/--	Excellent	Highly leveraged
Sierra Pacific Power Co.	BB+/Stable/--	Excellent	Highly leveraged
NV Energy Inc.	BB+/Stable/--	Excellent	Highly leveraged
Puget Energy Inc.	BB+/Stable/--	Excellent	Aggressive
Tucson Electric Power Co.	BB+/Stable/B-2	Strong	Aggressive
Texas-New Mexico Power Co.	BB/Positive/--	Strong	Aggressive
Public Service Co. of New Mexico	BB/Positive/--	Strong	Aggressive
PNM Resources Inc.	BB/Positive/--	Strong	Aggressive

*As of Jan. 4, 2012.

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J.E-2-12-14a
Attachment 2

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

January 11, 2012

Issuer Ranking:

U.S. Regulated Natural Gas Utilities, Strongest To Weakest

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Issuer Ranking:

U.S. Regulated Natural Gas Utilities, Strongest To Weakest

The 2012 outlook for credit quality in the U.S. gas utility sector will likely remain stable. While Standard & Poor's Ratings Services expects the U.S. economy to remain weak, we see little movement in regulated gas utilities' credit risk profiles during periods of economic change. The essential services that the sector provides and the rate-regulated nature of its businesses allow it to generate stable cash flows and recover costs even when the economy is weak.

The following list ranks all the rated companies in this industry from strongest to weakest based on rating and outlook. Companies with the same rating and outlook are further ranked by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry economic and ratings outlook, please see "U.S. Regulated Gas And Water Utilities' Credit Quality Should Remain Stable In 2012," published on Jan. 10, 2012.

Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies

Company	Corporate credit rating*	Business risk profile	Financial risk profile
Washington Gas Light Co.	A+/Stable/A-1	Excellent	Intermediate
WGL Holdings Inc.	A+/Stable/A-1	Excellent	Intermediate
Northwest Natural Gas Co.	A+/Stable/A-1	Excellent	Intermediate
NSTAR Gas Co.	A+/Watch Neg/--	Excellent	Intermediate
Southern California Gas Co.	A/Stable/A-1	Excellent	Intermediate
Piedmont Natural Gas Co. Inc.	A/Stable/--	Excellent	Intermediate
Questar Gas Co.	A/Stable/--	Excellent	Intermediate
Questar Corp.	A/Stable/A-1	Excellent	Intermediate
New Jersey Natural Gas Co.	A/Stable/A-1	Excellent	Intermediate
Northern Natural Gas Co.	A/Stable/--	Excellent	Intermediate
Laclede Gas Co.	A/Stable/A-1	Excellent	Intermediate
Laclede Group Inc. (The)	A/Stable/--	Excellent	Intermediate
KeySpan Energy Delivery New York	A/Stable/--	Excellent	Intermediate
Wisconsin Gas LLC	A-/Stable/A-2	Excellent	Significant
Indiana Gas Co. Inc.	A-/Stable/--	Excellent	Significant
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant
Vectren Corp.	A-/Stable/--	Excellent	Significant
Yankee Gas Services Co.	BBB+/Watch Pos/--	Excellent	Aggressive
Peoples Gas Light & Coke Co. (The)	BBB+/Positive/A-2	Excellent	Significant
North Shore Gas Co.	BBB+/Positive/--	Excellent	Significant
Peoples Energy Corp.	BBB+/Positive/--	Excellent	Significant

Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies (cont.)			
Public Service Co. of North Carolina Inc.	BBB+/Stable/A-2	Excellent	Aggressive
Sempra Energy	BBB+/Stable/A-2	Strong	Intermediate
Atlanta Gas Light Co.	BBB+/Stable/--	Excellent	Significant
AGL Resources Inc.	BBB+/Stable/A-2	Excellent	Significant
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	Strong	Significant
Atmos Energy Corp.	BBB+/Stable/A-2	Excellent	Significant
South Jersey Gas Co.	BBB+/Stable/A-2	Strong	Significant
South Jersey Industries Inc.	BBB+/Stable/--	Strong	Significant
Cascade Natural Gas Corp.	BBB+/Stable/--	Excellent	Intermediate
Southwest Gas Corp.	BBB+/Stable/--	Excellent	Aggressive
Connecticut Natural Gas Corp.	BBB/Stable/--	Excellent	Aggressive
Southern Connecticut Gas Co.	BBB/Stable/--	Excellent	Aggressive
ONEOK Inc.	BBB/Stable/A-2	Satisfactory	Intermediate
Alabama Gas Corp.	BBB/Stable/--	Satisfactory	Intermediate
PNG Cos. LLC	BBB-/Stable/--	Excellent	Aggressive
Bay State Gas Co.	BBB-/Stable/--	Excellent	Aggressive
NiSource Inc.	BBB-/Stable/A-3	Excellent	Aggressive
SEMCO Energy Inc.	BBB-/Negative/--	Excellent	Highly leveraged
SourceGas LLC	BB+/Stable/--	Excellent	Highly leveraged

*As of Jan. 3, 2012.

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J.E-2-12-14a
Attachment 3

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect

February 24, 2012

Issuer Ranking:

Canadian Utilities And Pipelines, Strongest To Weakest

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Issuer Ranking:

Canadian Utilities And Pipelines, Strongest To Weakest

The following list ranks Standard & Poor's Ratings Services' ratings, outlooks, and overall credit strength for Canadian electric utilities and generators, and gas distribution utilities and pipelines. The lists reflect ratings and outlooks as of Feb. 24, 2012. The rankings within each rating/outlook grouping (for instance, A/Stable/--) are based on relative overall credit quality.

The ranking list reflects several our view of overall relative credit quality within each rating category. We describe business risk and financial risk profiles in the utility sector using our corporate ratings risk matrix (for more information, please see "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect on the Global Credit Portal). Our purpose is to present rating conclusions in a transparent and standardized manner across all corporate sectors.

We categorize business risk profiles from "excellent" to "vulnerable" (see table 1). To determine a business risk profile, Standard & Poor's analyzes a utility's regulatory support; commodity exposure; operational performance; asset concentration; markets and service area economy; competitive position; and ownership, risk appetite, and governance. The business risk profiles of most regulated utilities fall in the "excellent" and "strong" categories. We tend to weigh business risk slightly more than financial risk when differentiating among investment-grade ratings.

Table 1

Business Risk And Financial Risk Profile Matrix

Business risk profile	--Financial risk profile--					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

We categorize financial risk profiles from "minimal" to "highly leveraged". To determine a financial risk profile, we analyze, amongst other things, a utility's sustainable cash flow strength with respect to its debt obligations, financial policies, liquidity and liability management, accounting and disclosure practices, and financial flexibility. Financial risk indicative ratios (see table 2) are not meant to be precise indications of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the matrix.

Table 2

Financial Risk Indicative Ratios For Corporate Issuers

	FFO/debt (%)	Debt/EBITDA (x)	Debt/capital (%)
Minimal	Greater than 60	Less than 1.5	Less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45

Table 2

Financial Risk Indicative Ratios For Corporate Issuers (cont.)			
Significant	20-30	3-4	45-50
Aggressive	Less than 12	4-5	50-60
Highly leveraged	Less than 12	Greater than 5	Greater than 60

FFO--Funds from operations.

An outlook is not necessarily a precursor of a rating change or CreditWatch action. "Positive" indicates that we believe there is a one-in-three likelihood of a rating action in the medium term for investment-grade issuers (generally up to two years) that could raise a rating; "negative" means we could lower a rating; "stable" indicates that ratings are not likely to change; and "developing" means we could raise or lower ratings. In determining an outlook, we consider any changes in the economic or fundamental business conditions (for more information, please see "General Criteria: Use Of CreditWatch And Outlooks," published Sept. 14, 2009).

Displayed ratings use the following format: long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates that we have not assigned a rating. Credit ratings are identical for local and foreign currency unless noted with the LC and FC designations. All commercial paper ratings listed are on Standard & Poor's global scale.

For the related industry report card, please see "Growth Poses Biggest Challenge To An Otherwise Stable Canadian Midstream And Utility Sector," published Feb. 15, 2012.

Table 3

Issuer Ranking: Canadian Utilities*

Electric utilities and generation

Issuers	**Corporate credit rating‡**	**Business risk**	**Financial risk**
Hydro One Inc.*	A+/Stable/A-1	Excellent	Significant
Canadian Utilities Ltd.	A/Stable/A-1	Excellent	Significant
ATCO Ltd.	A/Stable/--	Excellent	Significant
CU Inc.	A/Stable/A-1	Excellent	Significant
Hydro Ottawa Holding Inc.*	A/Stable/--	Excellent	Intermediate
Toronto Hydro Corp.*	A/Stable/--	Excellent	Significant
London Hydro Inc.*	A/Stable/--	Excellent	Intermediate
Enersource Corp.*	A/Stable/--	Excellent	Intermediate
Guelph Hydro Electric Systems Inc.*	A/Stable/--	Excellent	Significant
Horizon Holdings Inc.*	A/Stable/--	Excellent	Intermediate
Hamilton Utilities Corp.*	A/Stable/--	Excellent	Intermediate
Electricity Distributors Finance Corp.§	A	Excellent	Significant
ENTEGRUS Inc.*†	A/Negative/--	Excellent	Intermediate
Caribbean Utilities Co. Ltd.	A-/Stable/--	Excellent	Significant
AltaLink L.P.	A-/Stable/--	Excellent	Significant
Ontario Power Generation Inc.*	A-/Stable/--	Strong	Significant
FortisAlberta Inc.	A-/Watch Neg/--	Excellent	Significant
Fortis Inc.	A-/Watch Neg/--	Excellent	Significant
EPCOR Utilities Inc.	BBB+/Stable/--	Strong	Significant

Table 3

Issuer Ranking: Canadian Utilities* (cont.)			
Nova Scotia Power Inc.	BBB+/Stable/--	Strong	Significant
Emera Inc.	BBB+/Stable/--	Strong	Significant
Maritime Electric Co. Ltd.	BBB+/Stable/--	Strong	Significant
ENMAX Corp.*	BBB+/Stable/--	Strong	Significant
Brookfield Renewable Energy Partners L.P.	BBB/Stable/A-2	Satisfactory	Intermediate
TransAlta Corp.	BBB/Negative/--	Satisfactory	Intermediate
Capital Power L.P.	BBB/Negative/--	Satisfactory	Intermediate
Capital Power Corp.	BBB/Negative/--	Satisfactory	Intermediate
Northland Power Inc.	BBB-/Positive/--	Satisfactory	Intermediate
Algonquin Power Co.	BBB-/Positive/--	Satisfactory	Significant
AltaLink Investments L.P.	BBB-/Stable/--	Excellent	Aggressive
Innergex Renewable Energy Inc.	BBB-/Stable/--	Strong	Significant
Capstone Infrastructure Corp.	BBB-/Stable/--	Satisfactory	Significant
Gas distribution utilities and pipelines			
Inter Pipeline (Corridor) Inc.	A-/Positive/--	Excellent	Significant
TransCanada PipeLines Ltd.	A-/Stable/A-2	Excellent	Significant
TransCanada Corp.	A-/Stable/--	Excellent	Significant
Gaz Metro Inc. and Gaz Metro L.P.	A-/Stable/--	Excellent	Significant
Enbridge Gas Distribution Inc.	A-/Stable/A-1	Excellent	Significant
Enbridge Pipelines Inc.	A-/Stable/A-1	Excellent	Significant
Enbridge Inc.	A-/Stable/A-1	Excellent	Significant
Union Gas Ltd.	BBB+/Stable/A-2	Strong	Significant
Westcoast Energy Inc.	BBB+/Stable/--	Strong	Significant
Trans Quebec & Maritimes Pipeline Inc.	BBB+/Stable/--	Strong	Significant
Inter Pipeline Fund	BBB+/Stable/--	Strong	Significant
Pembina Pipeline Corp.	BBB+/Watch Neg/--	Strong	Significant
Tuscarora Gas Transmission Co.	BBB/Stable/--	Satisfactory	Modest
TC PipeLines L.P.	BBB/Stable/--	Strong	Significant
Veresen Inc.	BBB/Stable/--	Strong	Significant
AltaGas Ltd.	BBB/Stable/--	Strong	Significant

*Business risk and financial risk profiles reflect the stand-alone credit risk profile as per our government-related entity criteria. §Debt rating. †Previously Chatham Kent Energy Inc. ‡Ratings as of Feb. 24, 2012.

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EX 016-11

Application No. 1271597

Board File No. 5681-1

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF

GENERIC COST OF CAPITAL PROCEEDING

FAIR RETURN FOR AN ALBERTA UTILITY

WRITTEN EVIDENCE OF

DR. LAURENCE D. BOOTH

on behalf of

THE CITY OF CALGARY

and

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS (CAPP)

September, 2003

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APPENDIX A

CAPITAL STRUCTURE AND ADJUSTMENT FOR BUSINESS RISK

To set fair and reasonable rates the Board needs to set both a fair ROE and a fair capital structure for the regulated firm (equity ratio). In this appendix I discuss how the Board can determine the capital structure and other financial policies for the firms under its jurisdiction such that they can then all receive the same allowed ROE via an appropriate adjustment mechanism. It is important in this respect that the board recognise any perceived risk differences and adjust for them in a consistent manner, rather than repeatedly adjusting for the same risk differences in multiple areas.

I: Regulatory Tools for Managing Risk

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

$$P_0 = \frac{ROE * BVPS * (1-b)}{(K-g)} \qquad (1)$$

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

The discounted cash flow (DCF) model[1] is useful for thinking of the sources of risk to the investor. Some of these risks stem from the firm's operations and financing and others come from the capital market's perception of the firm and general capital market conditions. For regulated utilities we also add another dimension, which is the impact of *regulatory* risk. In terms of the DCF equation the actual earned return on equity **(ROE)** captures the business, financial and regulatory risk, which together I term ***income*** risk, whereas all the other factors are reflected in ***investment*** risk, which is the way in which

[1] See Appendix G for a discussion of the basic DCF model.

maximises the use of the tax advantages from debt financing, while maintaining the utility's financial integrity and ability to raise capital to provide service.[8] This amount of debt will vary across the different utilities depending on their net business risk after taking into account regulatory protection.

3: Business Risk Rankings

The risks faced by the stockholder in the DCF equation (1) can be divided into short and long term risks. The short term risks are essentially the ability of the regulated firm to earn its allowed ROE, which is what I previously termed income risk, while long term risks refer to the growth in these future cash flows and the risk of not being able to recover the capital invested.

The major short term risks stem from both cost and revenue uncertainty.

- On the cost side since regulated utilities are capital intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.
- On the revenue side the risks largely stem from rate design, critical features are:
  - Who is the customer and what *credit risk* is involved. For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments from the provincially appointed TA, who is responsible for system integrity, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.
  - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.
  - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

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[8] Generally in Canada this means at least a BBB bond rating or better for a reasonable sized utility. According to S&P in the US 43% of utility holding company debt is now BBB and a further 18% is non-investment grade.

The above risks are all moderated by whether or not the Board allows deferral accounts.

The medium and long term risks are mainly as follows:

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

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

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

I have discussed the business risk of the Alberta utilities with both The City of Calgary and CAPP's support team and have been informed by their analyses. As a result of this interaction, my judgement is that the lowest risk regulated utilities in Canada are currently electricity transmission assets, since these have the following characteristics:

* Minimal forecasting risks attached to O&M
* Revenue recovery via the TA through fixed monthly charges
* Limited (non existent) by-pass problems
* Minimal capital recovery problems, since there are many suppliers of electricity as a basic commodity.

* Deferral account for capital expenditures

In the AltaLink and ATCO Electric hearings earlier this year Professor Berkowitz and I recommended 30% common equity ratios based in part on the National Energy Board's 30% allowed common equity ratio for mainline gas transmission assets. The Board allowed Altalink 32% based on its business risk and an additional 2% based on the tax status of 25% of its equity ownership. Nothing has changed since the AltaLink hearing and I would continue to recommend 30% common equity for the electricity transmission assets involved in this proceeding, but accept the Board's 32% equity ratio as reasonable.

I would place the gas transmission pipelines as the second lowest risk group. Here it is important to distinguish between the full cost of service pipelines like Foothills that have many of the same characteristics as the electricity transmission operations mentioned above. In fact I would classify Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to AltaLink and ATCO Electric transmission. NGTL has marginally more risk than Foothills and the TCPL BC System, since it is exposed to bypass and recovers its revenues through a forward test year from a variety of shippers, rather than as a single monthly charge to the provincially appointed TA.

However, these risks are still minimal. NGTL sits at the heart of the Western Canadian Sedimentary Basis (*WCSB*) and although this basin is now maturing, it remains prolific, is not as mature as some of the other basins and is the natural intermediary for Northern as well as non-conventional gas such as coal bed methane. Further since the 1995 NGTL hearing, NGTL has become part of the TCPL system, has adopted distance sensitive tolls and has significantly increased its depreciation rate. The latter two are important changes.

Bypass risk depends on whether it is economic to build a new pipeline to compete with an existing one. If the existing pipeline (or gas LDC) is charging tolls that are not based on underlying economics but some other objective, such as developing gas reserves that are far from existing areas, then there is an implicit regulated subsidy that will encourage bypass. In this case, in order to avoid uneconomic duplication of facilities the regulator can either allow special bypass rates, or load retention service (LRS), to make sure that the load stays on system or change the rate structure to distance sensitive, economic based, tolls. In the case of NGTL this Board has allowed both.

Capital recovery depends on the continuing supply and demand for a firm's assets. When a depreciation rate is set the first step is to estimate the useful life of the asset, so that its cost can be correctly allocated over this useful life. This matching of revenues and costs is one of the basic principles of generally accepted accounting principles. As capital recovery risk increases then a shortening of an asset's useful life is accomplished through a higher depreciation rate. In RH-1-2002 the NEB increased the TCPL Mainline's depreciation rate from 2.89% to 3.42% to partially compensate for increased capital recovery risk. In contrast, it is my understanding that during the period when NGTL had negotiated rates, it negotiated an increase in its depreciation rate from the 2.96% rate at the time of its last GRA (1995) to the current level of 4.0%. Significantly in CAPP-NGTL-38c NGTL indicated that its plant would be substantially depreciated by 2021.

The combination of distance sensitive tolls, the ability to offer load retention service and a more rapid depreciation rate significantly reduce any increase in risk NGTL may have faced since 1995.[9] On its own I would judge that NGTL can maintain its financial flexibility on the same 30% common equity ratio the NEB allows Foothills and Westcoast's mainline gas transmission assets. This was what Professor Berkowitz and I recommended for the TCPL Mainline before the NEB in 2002. However, since NGTL is currently allowed 32%, based on the absence of a preferred share component, and is now almost indistinguishable from the TCPL Mainline, it makes sense to allow the same 33% common equity ratio the NEB now allows the Mainline.

The third group of utilities are the local distribution companies (LDCs), including both gas and electric. These companies are distinguished by their retail operations, which mean that their revenues are recovered from a large number of industrial, commercial and residential consumers. This exposes them to both the business cycle and weather

[9] The change in policy towards laterals and the maintenance of rolled in tolls would also tend to lower NGTL's risk.

fluctuations. This revenue recovery is also a function of their rate design that may expose them to commodity charges and a fixed and variable recovery charge.

The conventional yardstick for LDCs is that Consumers (Enbridge Gas Distribution Inc or EGDI) and Union Gas are both allowed 35% common equity by the Ontario Energy Board. However, whereas the Ontario Energy Board allows a purchase gas variance account (PGVA) to ensure that the full costs of gas are recovered, they are still subject to volume related variances. In contrast, the BCUC allows BC Gas (Teresen Gas) a more comprehensive deferral account, but limits the allowed common equity ratio to 33%. With these yardsticks I recommend the same 35% common equity ratio that Professor Berkowitz and I recommended in the ATCO Gas GRA for all the Alberta LDCs.[10]

Finally, there is ATCO Pipelines (AP). In testimony filed in May 2003 Professor Berkowitz and I recommended a 42% common equity ratio as the "upper end of a reasonable range" for AP based on the increased competition from NGTL and regulatory uncertainty. As a small intra-Alberta pipeline AP is vulnerable to predatory pricing from NGTL and is reliant on regulatory protection from this Board. This will emerge in the joint hearing into rate design for AP and NGTL scheduled for March 2004. Absent this hearing I would continue to regard 42% as the upper end of a reasonable range, given that the BCUC allows PNG, a smaller and much riskier pipeline, 36% common equity. Should clear principles emerge on intra Alberta pipeline competition and rate design that lower AP's risk, then I would judge PNG's 36% allowed common equity ratio to be the upper end of a reasonable range.

Consequently, I recommend the following common equity ratios:

Lowest risk:	Electricity transmission assets, for example AltaLink, 30%
Very low risk:	Gas transmission assets, for example NGTL, 33%
Average risk:	Gas and Electric LDCs, for example, ATCO Gas 35%

[10] Absent the merchant function the allowed common equity ratio can be reduced to at least the 33% of Terasen Gas. If the revenue requirement is recovered through a fixed delivery charge the allowed common equity ratio can be the same 30% I deem appropriate for the transmission wires and pipes.

Above average risk: ATCO Pipelines 36-42%, (depends on 2004 EUB decision)

In my judgement, none of the Alberta utilities are as risky as Pacific Northern Gas (PNG) or Gaz Metropolitain (GMI).

4: Utility Benchmarks

There are no publicly traded pure utilities left in Canada that also have a reasonable price history, except Pacific Northern Gas. This makes it difficult to estimate risk by looking at stock market data or by examining their financial statements. However, the National Energy Board in its Annual Report publishes abbreviated information on the regulated assets of the mainline gas pipelines under its jurisdiction. The most important information is a comparison of the actual to their allowed ROEs. For the Class 1 gas transmission pipelines, this information is in Schedule A1.[11] All of these pipelines are now part of TransCanada Pipelines,[12] but this has not always been the case and the NEB still maintains separate data for each pipeline.

Foothills and Alberta Natural Gas (ANG or now the TCPL BC system) are full cost of service pipelines and exactly earn their allowed ROE.[13] In contrast, the TCPL Mainline and TQM are forward test year plus deferral account companies, similar to the Alberta utilities in this hearing, in their case, they have consistently over earned their allowed ROE by 0.23-0.36%. It is difficult to see how this persistent over-earning can be classified as more "risk." Implicitly this was also the NEB's decision when it allowed all of these pipelines the same 30% common equity for their mainline gas transmission pipelines. However, *since Foothills exactly earns what the NEB allows, by definition,*

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[11] This data was confirmed in CAPP NGTL-17

[12] TQM is 50% owned by TCPL.

[13] In 2002 ANG failed to earn its ROE due to agreed sharing in the TCPL merger agreement.

EB-2005-0520
EXHIBIT K2

BUSINESS RISK AND CAPITAL STRUCTURE

FOR UNION GAS LIMITED

Evidence of Laurence D. Booth
on behalf of
the Consumers Council of Canada, the Industrial Gas Users' Association and the Vulnerable Energy Consumers Coalition

Before the

Ontario Energy Board

April 2006

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A. The core of the testimony of Dr. Vilbert is to estimate the WACC from a sample of UHCs and use them as a proxy for Union Gas. As I have demonstrated above there is little doubt that the Canadian UHCs are riskier than their underlying regulated assets due to their periodic misadventures in non-regulated areas. This UHC risk will be reflected in their higher WACC. In turn using the methodology of Dr. Kolbe this must result in a higher deemed common equity ratio. Further in interrogatory response J2-10 Dr. Vilbert was asked what adjustments he made for the higher risk of the UHCs, and the answer was none. Further Dr. Vilbert admitted to doing no tests to see whether his sample of US UHCs were comparable to Canadian UHCs, let alone Canadian regulated assets.

Q. WHAT COMPARATORS WOULD USE FOR UNION GAS?

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

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

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

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

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

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

  - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue

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in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

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

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

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

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

On this basis I judged the lowest risk regulated utilities in Canada to be electricity transmission assets, since these have the following characteristics:

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

and recommended 30% common equity ratios.

I then placed the gas transmission pipelines as the second lowest risk group. Here I classified Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to electricity transmission assets with NGTL having marginally more risk than Foothills and the TCPL BC System, since it is exposed to bypass and recovers its revenues through a forward test year from a greater variety of shippers. However, the combination of distance sensitive tolls, the ability to offer load retention service and a more rapid depreciation rate significantly reduce any increase in risk NGTL may have faced since 1995. I therefore judged that on its own NGTL could maintain its financial flexibility on the same 30% common equity ratio allowed mainline gas transmission assets. However, because NGTL was then allowed 32% and was almost "indistinguishable" from the TCPL Mainline, I recommended the same 33% common equity ratio then allowed the Mainline.

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

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

In the two years since the Alberta generic hearing I have testified in business risk hearings for the TransCanada Mainline, FortisBC and Terasen Gas and have not changed the above judgment. Given the very low, if not non-existent, income risk, ROE regulated utilities in Canada continue to have the very stable ROI necessary to support large amounts of tax efficient debt financing. The only changes since then have been that the NEB has increased the Mainline's common equity ratio to 36%. There seems to be two reasons for this first the Mainline refinanced its 10% preferred share component and replaced them with junior subordinated debentures and second the entry of Alliance as a "competitor" has taken load from the Mainline, such that it is running at significantly less than capacity with the fear that the WCSB will not generate the new supplies to allow it to run full again.[10] Neither of these factors are relevant for Union Gas. The only other significant change is that the BCUC has recently increased the allowed common equity ratio of Terasen Gas from 33% to 35% to bring it in line with Union and EGDI. Notably Westcoast Transmission (Duke Energy Transmission) has negotiated a 31% common equity ratio up from the 30% allowed by the NEB under RH-2-94. Overall there is nothing in recent allowed common equity ratios that cause me to change my judgment concerning the appropriateness of Union's common equity ratio.

Q. WHY HAVE YOU NOT DISCUSSED UNION'S INCREASED RISK FACTORS?

A. I don't think that they are material. I have heard Dr. Sherwin and other company witnesses discuss "increases" in risk faced by various regulated utilities since I first testified in 1985. However, the ability of regulated utilities to earn their allowed ROE has not been

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[10] The NEB has also increased the Mainline's depreciation rate to compensate for supply problems from the WCSB.

It is clear from this comment from S&P that it is their disenchantment with events in the US that has triggered their review of regulatory protection in Canada. Further they are not the only ones.

In a recent article in Public Utilities Fortnightly (August 2004) two members of the New Jersey Board of Public utilities state

> "ring fencing holds out the prospect for insulating regulated utilities from the traditional failed diversification investments of the parent holding company….. Successful ring fencing is even more critical considering that state regulators are facing challenges created by failures of corporate governance, accounting scandals, and in some cases alleged criminal conduct in energy markets. Ring fencing may be the only regulatory device capable of levelling the playing field and forcing the holding companies to absorb the consequences of failed non-utility investments."

With FERC failing to implement ring fencing and these types of concerns being raised in the US it is hardly surprising that S&P has adopted a negative tone towards both US and Canadian utilities.

Q. IS THE US EXPERIENCE RELEVANT FOR CANADA?

A. To some extent yes. Although we have not had the problems that they have had in the US that does not mean that we can't have them. Further, with Duke Energy's acquisition of Union Gas there could always be the sort of problems that have bedevilled Enron and other US UHCs, where when the parent ran into problems they looked to the regulated subsidiary to strip it of cash. As of the current point of time Union's bonds seem to trade on their DBRS rather than the S&P rating. However, during 2005 Union obtained loans from and made loans to its immediate parent Westcoast indicating that Union does not truly manage its own cash flow. This lack of structural insulation makes it impossible for Union Gas to have an S&P bond rating that reflects its own risk. At some point in the future this may cause its borrowing cost to reflect Duke Energy's BBB bond rating, rather than its own credit. I would recommend that the Board take measures to structurally insulate both Union and EGDI from its parents to ensure that ratepayers only pay the legitimate borrowing cost attached to the regulated activities. Otherwise there may be a long run risk stemming from Union's ownership by a risky US

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energy company as well as potential short term arguments as to whether Union's BBB rated debt costs should be passed on to Union's ratepayers.

Q. DOES UNION GAS HAVE FINANCIAL FLEXIBILITY WITH YOUR RECOMMENDATION?

A. Yes. Union filed a statement with the OSC as to its interest coverage ratio on September 20, 2005 which stated:

> **EARNINGS COVERAGE RATIO**
> **Earnings Coverage Ratio**
> After giving effect to all issues and retirements of long-term debt since December 31, 2004, the annual interest requirements on the consolidated long-term debt of the Company for the twelve months ended September 30, 2005 were $155 million and for the twelve months ended December 31, 2004 were $155 million. Consolidated net income of the Company for the twelve months ended September 30, 2005, calculated before interest on consolidated debt and income taxes, amounted to $325 million, which is 2.10 times the Company's annual interest requirements on consolidated long-term debt for that period. Consolidated net income of the Company for the twelve months ended December 31, 2004, calculated before interest on consolidated debt and income taxes, amounted to $349 million, which is 2.25 times the Company's annual interest requirements on consolidated long-term debt for that period.

So with its current allowed ROE, embedded interest cost and 35% common equity ratio Union had an ICR of 2.25 for 2004 and 2.10 for 2005 for its September year ends. These both exceed the target of 2.0 in the trust indenture for issuing unsecured debt. Further in the EBRO499 Decision the Board accepted that Union would have the following ICRs at a 9.64% ROE

	1999	200	2001	2002	2003
ICR	2.08	2.02	2.09	2.15	2.16

So the Board has accepted in the past that ICRs marginally above 2.0 and less than Union's ICRs in 2004 and 2005 were acceptable. Further Union's marginal ICR is significantly higher than these levels.

FAIR RETURN FOR TERASEN GAS INC (TGI)

EVIDENCE OF

Laurence D. Booth

BEFORE THE

British Columbia Utilities Commission

August 2009

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EXECUTIVE SUMMARY

The Joint Industry Electricity Steering Committee (JIESC), the Commercial Energy Consumers Association of British Columbia (CEC),and The British Columbia Old Age Pensioners Organization et. al. (BCOAPO), collectively the British Columbia Utility Customers have asked me to review Terasen Gas Inc's (TGI) rate application and associated evidence and to offer an opinion as to the fair rate of return on common equity (ROE) and appropriate capital structure and whether the ROE adjustment mechanism continues to be appropriate.

My overall assessment is:

- There has been no material change in TGI's business risk and I recommend that the current deemed common equity ratio of 35% be maintained. Further the BCUC formula ROE continues to give fair ROEs, but if it is to be rebased my recommended ROE is 7.75% and it should be reset at this level with the continuation of a 75% adjustment to forecast long Canada bond yields. The recent confirmation of TGI's "A" bond ratings by both DBRS and Moody's confirms that it remains an excellent credit, while the recent stock market crash confirms the low risk nature of utility shares.

- My judgment is that the Canadian economy has bottomed out from a short but deep recession that started in 2008Q4. In contrast the US economy has been in recession for almost two years and has further to go in its deleveraging. The US recession was caused by a credit crunch resulting from disastrous losses incurred by banks in the sub-prime mortgage market. As major US and UK banks failed, the remainder reduced lending to shore up capital, while investors reacted by shedding risky securities to invest in the safe harbour of government securities. In response Treasury Bill yields collapsed, and even turned negative in 2008Q4 in the US, and liquidity in many areas of the bond market disappeared creating historically high spreads on even high grade credits. These US problems spread around the world as US capital was repatriated creating the world's first global economic recession.

- The US credit crunch exacerbated a normal cyclical recession and caused the biggest stock market crash for 70 years and fears of a Great Depression II. However Herculean efforts by the US Government and Treasury have restored investor faith in the US banking system. Further, capital injections from the TARP program have allowed US banks to return to their normal activities, so that liquidity has returned to the bond market and both yields and spreads on investment grade credits have fallen dramatically. In this respect it is important to note that the Company's evidence was prepared at a time when the recession and financial market conditions were at their worst. However most of this has now passed. The Canadian economy has now moved into recovery mode, dividend yields on the TSX have dropped by over 1.0% as the TSX has itself rebounded by over 40% since its March lows and spreads on "A" bonds over equivalent maturity LTC bonds have more than halved. Further long term Canada bond yields have recovered and I rebalanced rates after Methanex closed its doors and PNG lost more than half its load, and allowed a large industrial deferral account. In each case PNG was not allowed to suffer in isolation, instead the regulator stepped in to try and help the survival of the company.

Another recent example is the potential liability to EGDI caused by the Supreme Court of Canada with respect to a 5% late payment penalty, a penalty which breached the criminal code in terms of a fair rate of interest. On page 3 of the October 31, 2006 MD&A EGDI simply states

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

That is, that the settlement of this liability would not be paid by shareholders but simply passed on to ratepayers. Further in 2008 the OEB did allow EGDI to recover these costs and was supported in this decision by the Consumers Association of Canada. Again this demonstrates the dynamics of Canadian regulation and that most risks end up not with the shareholders but ratepayers.

As the actual versus allowed ROE data for the major utilities indicates none of the risks advanced in regulatory hearings involving those utilities have materially harmed their shareholders. Consequently, in my judgement utilities in Canada claim higher ROEs and common equity ratios on the basis of risks that they do not in fact bear. Moreover, in the future I expect this to continue and any future risks, should they materialise, will similarly be allocated to ratepayers and not to shareholders.

CONCLUSION

Overall I see nothing in TGI's business risk to indicate that the allowed common equity ratio should change from the current allowed 35%. I would also point out that the allowed common equity ratio was 33% until the 2006 Decision and nothing of any substance seems to have changed since then. It is also important that both Moody's and DBRS confirmed TGI's bond rating at "A" in May 2009, when the credit crisis was still severe and the economy in recession. It is quite clear that TGI's deemed common equity ratio is consistent with its low business risk and supports an exceptionally strong bond rating.

AUC
Alberta Utilities Commission

2011 Generic Cost of Capital

December 8, 2011

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3.11 The Commission's awarded ROE

139. The Utilities requested an ROE of 10.375 per cent based on the expert evidence of Ms. McShane.

140. Dr. Booth's position was that no Alberta utility had difficulty raising capital since the last generic cost of capital proceeding and that no increase in ROE is warranted. If anything, the ROE should be reduced.

141. The UCA submitted that the fair ROE is in the range of 8.0 to 8.5 per cent and the Commission should approve an ROE not higher than 8.3 per cent.[103]

142. The CCA accepted the ROE recommendation of Drs. Kryzanowski and Roberts of 8.3 per cent for 2011and recommended that the Commission approve an ROE of 8.4 for 2012.[104]

143. In this decision, the Commission has set out to establish a fair rate of return on equity for 2011 and going forward for the utility companies it regulates. The awarded ROE must be based on an estimate of the risk-adjusted opportunity cost of equity capital. The Commission must estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than in other investments of similar risk that are available in the market. The difficulty that the Commission faces is that the ROEs that are available to be earned on investments of similar risk are not directly observable.

144. In keeping with the Commission's determinations above, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities. The Commission has reviewed the models and approaches adopted by the various parties and, based on the analyses above, has found that some of the CAPM and DCF results filed in this proceeding (including an analysis of the expected overall Canadian stock market returns) will form the primary basis for its ROE determination.

145. In making its ROE determination, the Commission is mindful of the uncertainties created by the financial crisis that began in the third quarter of 2007 and its lingering effects, which have not fully abated. The Commission found that, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

146. The Commission found that a reasonable CAPM estimate is in the range of 6.4 to 9.0 per cent based on its analysis of the forecast risk free rate, the market equity risk premium and beta.

147. The Commission also found that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming the equity ratio has been set to target a credit rating in the A range. The Commission concludes that the DCF results appear to suggest that investors expect a return of about nine per cent on utility investments, assuming investors agree with analysts' growth forecasts. However, as noted above, the Commission remains concerned about the impact of optimistic growth forecasts in this result. This concern is bolstered by the results of the DCF analysis applied to the overall market which suggested returns in the range of 7.1 to 10.1 per cent.

103 Exhibit 210, UCA argument, paragraph 138 and 149.
104 Exhibit 211, CCA argument, paragraphs 32 and 77.

148. The evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

149. Having considered and weighed all of the evidence and assessed it in the context of the lingering credit market volatility, and recognizing that there has been a reduction in the risk free rate of some 60 basis since 2009 by the close of the record of this proceeding, the Commission finds that some reduction in the ROE awarded in Decision 2009-216 is warranted. Accepting that some of the reduction in the risk free rate may be offset by an increase in the market equity risk premium, the Commission considers that a generic ROE of 8.75 per cent is reasonable for 2011.

4 Return to the formula adjustment in 2012

150. Having determined the generic rate of return on equity for 2011, the Commission must consider how that rate of return will be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula approach discontinued in 2009 should be reinstated and if so, what type of formula for annual adjustments to ROE should be adopted by the Commission.

151. In Decision 2004-052, the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or Board) adopted the annual adjustment formula for setting the generic ROE based on 75 per cent of the change in long Canada bond yields:[105]

$$ROE_{New} = \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield})$$

152. This formula was discontinued in Decision 2009-216, because of the economic crisis conditions observed at the time of the 2009 GCOC proceeding. Specifically, the Commission concluded that the historical relationships upon which the formula was based had not yet been re-established in the aftermath of the financial crisis.[106]

153. In this proceeding, the Utilities recommended that the Commission not adopt an automatic adjustment formula at this time for two reasons. First, the Commission's performance-based regulation (PBR) initiative for distribution utilities could change the risk profile of the distribution utilities and may require the re-evaluation of the fair ROE. Second, as outlined in Section 3.2 above, the Utilities argued that there remained considerable risk in the global economy and capital markets.[107]

154. However, the Utilities submitted that, if the Commission determined that an automatic adjustment mechanism is warranted for 2012, the formula adopted by the OEB in its Report EB-2009-0084 should be used. The OEB formula is as follows:

$$\begin{aligned} ROE_{New} = \text{Initial ROE} &+ 50\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ &+ 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

155. The Utilities indicated that Ms. McShane's independent analysis supported the factors and weightings used in this formula, based on the historical relationships among the utility cost of equity, long-term government bond yields and corporate bond yield spreads.

[105] Decision 2004-052, page 32.
[106] Decision 2009-216, paragraphs 418-420.
[107] Exhibit 209, Utilities argument, paragraphs 122.

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156. The UCA witnesses, Drs. Kryzanowski and Roberts, agreed that the formula adopted by the OEB reflects an appropriate adjustment structure. The UCA's position was that the Commission should return to a formula approach to setting allowed ROEs on a generic basis for the Alberta utilities because of the practical advantages resulting from regulatory efficiency. The UCA submitted that a properly designed ROE formula provides reasonably accurate estimates of the true cost of equity over a reasonable period.

157. Based on their opinion that credit markets had normalized, Drs. Kryzanowski and Roberts did not share the Utilities' view that the return to a formula would not be beneficial at this time. Furthermore, the UCA witnesses pointed out that introducing a utility bond spread component will mitigate any remaining concerns as to the financial market volatility.[108] With respect to the Utilities' concerns related to the ongoing PBR proceeding, the UCA expressed the opinion that the PBR may not involve any material changes in business risk. Additionally, the UCA indicated that one would expect changes in business risk to be addressed through capital structure adjustments rather than ROE adjustments, in accordance with past practice in Alberta.[109]

158. Dr. Booth, testifying on behalf of CAPP, proposed a modified formula that reflects 75 per cent of the change in the Government of Canada long bond yield and 50 per cent of the change in utility bond spreads:

$$ROE_{New} = \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ + 50\% \times (\text{Change in utility bond yield spread})$$

159. Dr. Booth explained that the 75 per cent adjustment factor is consistent with the formula that the Commission and its predecessor used between 2004 and 2009, and is supported by his analysis of market and utility risk premia.[110] By contrast, CAPP submitted that the formula proposed by Ms. McShane, with the 50 per cent adjustment factor for the Government of Canada long bond yield, would imply ROEs higher than those determined by regulators in that time period, including this Commission's predecessor.

160. CAPP also pointed out that the Quebec Régie de l'Energie accepted Dr. Booth's modified formula in a recent Gazifere decision (D2010-147) and will use it beginning in 2012.

161. The CCA indicated that none of the formulae proposed in this proceeding appear to be based on any financial analysis as to their validity and submitted that it prefers the Commission not return to an adjustment formula but periodically set a generic ROE.[111]

Commission findings

162. In Decision 2009-216, the Commission observed that due to the then-existing credit crisis conditions, the relationships among various market indicators were not stable and decided not to employ an adjustment formula for 2010. As discussed in Section 3.2 above, the evidence in this proceeding demonstrated that, although there has been some improvement in the financial environment, credit markets remain volatile. Referring to the financial community's concerns with the European sovereign debt, Dr. Booth summarized this view as follows:

[108] Exhibit 210.02, UCA argument, paragraph 16.
[109] Ibid., paragraph 21-22.
[110] Exhibit 78.02, evidence of Laurence D. Booth, paragraphs 180-184.
[111] Exhibit 211, CCA argument, paragraph 21.

> The fact is that we don't know all of the linkages in the credit default swap market, so that is a palpable nervousness in the bond market. That is something that is highly unusual. It is still there. It is nowhere near as bad as it was three years ago, but it is there, and we do not have a normal market.[112]

163. As the Commission explained in Decision 2009-216, the 2004 formula was developed based on the expectation that the required rate of return for utilities moves in the same direction as the return on 30-year Government of Canada bonds. The Commission found that, during a time of adverse market conditions, this expected relationship between interest rates and the required return on equities does not necessarily hold.[113]

164. All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula. Moreover, as Dr. Booth's explained, such a formula would be counter-cyclical because allowed returns would increase in difficult economic times and decrease in strong economic times, but over the business cycle this will average out.[114]

165. The Commission agrees with the interveners' arguments that a modified formula that accounts for changes in corporate bond spreads partially corrects for the drawbacks of a single-variable formula. Nevertheless, the Commission has considered the evidence of continuing credit market volatility and finds that a return to the formula mechanism for annual adjustments to ROE is not warranted at this time.

166. Accordingly, the Commission will not employ an adjustment formula for 2012. At the same time, as noted in the Decision 2009-216, the Commission is not prepared to preclude a return to some form of formula-based adjustment mechanism in the future, once the capital markets have stabilized and are once again considered reasonably predictable.[115] As such, the Commission is prepared to revisit the re-introduction of an automatic adjustment mechanism once the credit markets are more predictable and the Commission can be confident that the relationships implied in the formula will continue.

167. As explained in Section 3.11 of this decision, the Commission has determined that a fair generic rate of return on equity for Alberta utilities for 2011 is 8.75 per cent. Given the December 8, 2011 issue date of this decision and the fact that the record closed on September 9, 2011, the Commission is mindful of the proximity of this decision date to 2012. Considering the substantial drop in interest rates by the close of the record, the Commission sees no reason to find that the risk free rate of 3.4 to 3.8 per cent that it has accepted as reasonable for 2011 would not also be reasonable for 2012. The Commission does not consider that adjustments to any of its other findings with respect to the establishment of a reasonable ROE for 2011 are warranted for 2012. Accordingly, the Commission concludes that an ROE of 8.75 per cent is fair for both 2011 and 2012.

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[112] Transcript, Volume 7, page 911, lines 8 to 13.
[113] Decision 2009-216, paragraphs 417 and 418.
[114] Exhibit 207.02, paragraph 97.
[115] Decision 2009-216, paragraphs 420-422.

168. In addition, the Commission is setting the allowed ROE for 2013 at 8.75 per cent on an interim basis. The Commission will initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis. The Commission considers that establishing an allowed ROE for 2012 and setting an interim ROE for 2013 will provide for a more supportive, and predictable regulatory environment.

5 Capital structure matters

5.1 Introduction

169. To satisfy the fair return standard, the Commission is required to determine a capital structure (equity ratio) for each of the utilities that are the subject of this proceeding. In this decision, the Commission has established a generic ROE of 8.75 per cent which will be applied uniformly to all of the utilities. Consistent with the approach taken in the previous GCOC decisions, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

170. As the Commission noted in Decision 2009-216, in general, the return required by investors on debt is lower than the return required on equity. This is because debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in the capital increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk: debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and pay them their expected return.

171. This risk is usually assessed by various interest coverage calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor's (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various interest coverage metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations.

172. In this decision, the Commission will establish the capital structure for each utility that, in the Commission's judgment, would allow a stand-alone utility to maintain a credit rating in the A range, subject to company-specific circumstances. To do so, the Commission will first consider the impact of changes in the credit environment since the time of the 2009 GCOC proceeding. The Commission will then analyze the equity ratios that are required to attain the minimum credit metrics that were identified in Decision 2009-216. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted.

173. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2009-216 with the equity ratios recommended by the applicants and interveners in this proceeding.

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Table 7. Recommended vs. currently approved equity ratios

	Last approved[116] (%)	Recommended by the Utilities[117] (%)	Recommended by the UCA[118] (%)	Recommended by the CCA[119] (%)	Recommended by CAPP[120] (%)
Electric and Gas Transmission					
ATCO Electric TFO	36	38	34	36	
AltaLink	36	38	36	36	
ENMAX TFO	37	39	30	36	
EPCOR TFO	37	39	33	36	
ATCO Pipelines	45	47 (for 2011) 44 (for 2012)[121]	42 (for 2011) 30 (for 2012)	42 (for 2011) 40 (for 2012)	35 (for 2012)
Electric and Gas Distribution					
ATCO Electric DISCO	39	41	35	37	
ENMAX DISCO	41	43	35	39	
EPCOR DISCO	41	43	35	39	
ATCO Gas	39	41	34	37	
FortisAlberta	41	43	35	39	
AltaGas	43	45	40	41	

5.2 Credit environment

174. Much of the ROE and capital structure discussion in this proceeding centered on whether markets have returned to normal and whether the credit crisis discussed in Decision 2009-216 has passed. As discussed in more detail in Section 3.2 above, the Utilities cautioned that, while markets improved since the peak of the crisis, they have not returned to normal conditions. The interveners argued that economic parameters relevant to the cost of capital determinations have improved significantly and could be considered normal.

175. The Utilities submitted that, due to the persistence of significant downside risks to Canadian and global capital markets and economies, the two per cent across-the-board increase in common equity ratios approved in Decision 2009-216 was still relevant. Furthermore, Ms. McShane, who appeared on behalf of the Utilities, expressed her opinion that rating agencies do not view this across-the-board increase as temporary and, therefore, any reduction to equity ratios in the current proceeding could send negative signals to the market. As such, Ms. McShane used the capital structures approved in Decision 2009-216 as the point of departure in developing the Utilities' generic capital structure recommendations.[122]

176. In contrast, the UCA witnesses, Drs. Kryzanowski and Roberts, recommended that the Commission reverse the two percentage point equity ratio increase it awarded to all of the utilities in the 2009 GCOC. Their reasoning was that the additional two per cent was primarily awarded in order to account for the effects of the credit crisis, and because the credit crisis is

116 Decision 2009-216, Table 17, page 107.
117 Exhibit 209, Utilities argument, paragraph 129 (unless noted otherwise).
118 Exhibit 210.02, UCA argument, paragraph 215.
119 Exhibit 211, CCA argument, paragraph 58 (corrected as per Exhibit 213).
120 Exhibit 207.02, CAPP argument, paragraph 97.
121 Exhibit 208, ATCO Pipelines argument, paragraph 1.
122 Exhibit 209, Utilities argument, paragraphs 137-138.

over, there is no need to continue providing the Utilities with that additional financial flexibility.[123]

177. The UCA witnesses did not agree with Ms. McShane's position that the two per cent increase awarded in Decision 2009-216 was permanent and submitted that such an approach advocates the need for a permanent increase in shareholder returns, not because of what the actual capital market conditions were at the time of the decision, but because of the risk that problems similar to the financial crisis might arise in the future. Drs. Kryzanowski and Roberts submitted that the credit crisis was a rare event occurring approximately once in 75 years, and as such, it would not be fair to provide a permanent bonus to utility shareholders in order to insulate them against the potential effects of a near-catastrophic event that may not happen again for decades.[124]

178. The CCA supported the removal of the across-the-board two per cent increase in equity ratios awarded in the 2009 GCOC decision as proposed by the UCA, with the exception of the TFOs and ATCO Pipelines as further discussed below.[125] CAPP did not recommend any equity ratios other than for ATCO Pipelines, but did note that the financial market situation had stabilized and the need for any adjustment on this account was significantly reduced from the time of the 2009 GCOC decision when the Commission remained concerned about an uncertain future.[126]

Commission findings

179. As the Commission observed in Section 3.2 above, by the time of the 2011 GCOC hearing, economic parameters relevant to cost of capital determinations had improved significantly since the 2009 GCOC proceeding. Therefore, while cognizant of the lingering uncertainty in the debt markets related to concerns over sovereign debt in Europe and the U.S., the Commission agrees with Dr. Booth's opinion that the need for an adjustment to account for the financial crisis is reduced from the time of the 2009 GCOC decision.

180. However, as the Utilities pointed out, the credit crisis was only one of several factors that led to the two percentage point increase in equity thickness awarded in Decision 2009-216. Therefore, the Commission does not accept the UCA's proposal to reverse the two per cent equity ratio increase, solely because the credit crisis concerns have somewhat abated.

5.3 Credit metric considerations

5.3.1 Financial ratios, capital structure and actual credit ratings

181. Credit ratings measure the credit-worthiness of a firm. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments. This, in turn, allows the company to borrow at a lower interest rate. Utilities usually seek to maintain a credit rating in the A range.

182. As discussed in Section 5.1**Error! Reference source not found.** above, credit metrics (financial ratios) are an important part of bond rating agencies' considerations when assessing

123 Exhibit 210.02, UCA argument, paragraph 225.
124 Ibid., paragraphs 228-321.
125 Exhibit 211, CCA argument, paragraph 52.
126 Exhibit 207.02, CAPP argument, paragraph 90.

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the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:

- EBIT coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs
- funds for operation (FFO)/debt, which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt
- FFO coverage, which is the company's funds from operations plus interest divided by total interest costs

183. The Commission observed in Decision 2009-216 that a number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby making it possible to directly see the equity ratios and credit metrics that are associated with stand-alone regulated utilities that have credit ratings in the A range. Consequently, the Commission examined the credit ratings of those companies for which credit rating reports were available on the record, in order to gain some insight into the credit metrics required to achieve an investment grade credit rating for a stand-alone utility.

184. In Decision 2009-216, the Commission observed the following minimum credit metrics associated with an A-range credit rating:[127]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3%

185. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

186. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid point of 38.5 per cent.[128]

187. The sample group of utilities that were examined in arriving at this observed range of equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

188. In this proceeding, the Utilities noted that the importance of debt ratings in the A category for the Alberta utilities was reviewed in detail in the 2009 GCOC process, when the Commission established a capital structure that would allow a stand-alone utility to maintain a credit rating in the A range. In that regard, the Utilities submitted that there have been no fundamental changes in the capital markets or utility requirements for access to debt capital that would warrant revisiting that conclusion.[129]

[127] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[128] Ibid., paragraph 359.
[129] Exhibit 209, Utilities argument, paragraphs 135.

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189. The Utilities' position on the acceptability of the minimum credit metrics set out in Decision 2009-216 was not explicitly stated in argument, but appeared to be implicitly accepted. In particular, Ms. McShane testified that she used the minimum credit metrics observed in Decision 2009-216 as a point of departure.[130]

190. In her evidence, Ms. McShane also provided a review of changes in the equity ratios adopted for the Canadian peers of the Alberta utilities. Specifically, Ms. McShane indicated that, since the close of the oral portion of the last GCOC proceeding, there have been a number of increases in equity ratios approved by regulators. Based on her observation that the average regulated common equity ratio for utilities outside Alberta was 40 per cent, Ms. McShane considered this number to be a reasonable benchmark equity ratio for an average risk Alberta utility.[131]

191. The UCA submitted that it accepted the minimum credit metrics set out in Decision 2009-216 as reasonable guidelines, but emphasized Drs. Kryzanowski and Roberts' view that credit ratings do not follow a formula and depend on numerous qualitative factors and an examination by the rating agencies of numerous aspects of the businesses for which the ratings are prepared. The UCA witnesses also noted that their recommended equity ratios were generally consistent with the minimum equity ratios identified by the Commission.[132]

192. The CCA submitted that it did not accept benchmarking to the awards of other regulators as a tool for determining capital structure, as this method leads to a circularity problem. The CCA noted it accepts regulatory benchmarking only for information purposes, and only for comparison of methods, not for the actual awards.[133]

Commission findings

193. As discussed in Decision 2009-216, utilities usually seek to maintain their credit rating in the A range to avoid paying higher interest rates on debt typically associated with lower rating categories. Furthermore, as the Commission observed recently in Decision 2011-453[134] dealing with AltaLink's 2011-2012 GTA, a lower credit rating may limit a company's access to capital markets. In particular, the Commission noted that, as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions.[135]

194. Therefore, the Commission reaffirms its finding that it is important to target the debt ratings for the Alberta utilities in the A category, as established in the 2009 GCOC process. The Commission agrees with the parties to this proceeding that minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, can be accepted as reasonable guidelines for the purposes of this proceeding.

195. With respect to Ms. McShane's recommended benchmark equity ratio of 40 per cent, the Commission agrees with the CCA that equity ratios awarded by other regulators are of interest

130 Transcript, Volume 2, page 242, lines 8 to 11.
131 Exhibit 86.01, Kathleen McShane Opinion, pages 30-32.
132 Exhibit 210.02, UCA argument, paragraphs 156-160.
133 Exhibit 211, CCA argument, paragraphs 50 and 51.
134 Decision 2011-453: AltaLink Management Ltd. 2011-2013 General Tariff Application, Application No. 1606895, Proceeding ID No. 1021, November 18, 2011.
135 Decision 2011-453, paragraph 798.

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but are far from determinative of the capital structure this Commission should award. Furthermore, in Decision 2009-216, the Commission observed the actual equity ratios of the utilities in the A range rating category. Ms. McShane did not specify whether her analysis of capital ratios awarded by other regulators was limited only to the A-rated utilities.

5.3.2 Equity ratios associated with minimum credit metrics

196. In Decision 2009-216, the Commission provided a sensitivity analysis of the three key credit metrics to changes in the equity ratio. Assuming an embedded cost of debt of 6.5 per cent, an ROE of 8.75 per cent (the 2009 placeholder level), an income tax rate of 29 per cent, and assuming the annual depreciation expense as a percentage of invested capital equal to the utility average of six per cent, the Commission calculated the following minimum equity ratios required to achieve the observed minimum credit metrics:[136]

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 34 per cent.
- Minimum equity ratios in the range of 30 to 36 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 33 per cent was required to achieve an FFO coverage ratio of at least 3.0.

197. Ms. McShane proposed to update the Commission's analysis in Decision 2009-216 by making three adjustments. The first was to assume a reduction in average debt costs for the average utility. The second was to include an assumed five per cent construction work in progress (CWIP) in the credit metric calculation for the hypothetical average utility. The third involved recalculating the hypothetical credit metrics using the lower tax rates that apply in 2012.

198. With respect to the first adjustment, Ms. McShane noted that a review of the 2009 embedded debt costs provided by the Alberta utilities in their Rule 005[137] filing requirements indicated that there has been a marginal decline since 2007 (less than 10 basis points). Therefore, Ms. McShane proposed to use a 6.4 per cent average embedded cost of debt as compared to the 6.5 per cent rate used by the Commission in Decision 2009-216, which would have the effect of improving credit metrics and decreasing the necessary equity ratio.[138]

199. Next, Ms. McShane indicated that even a relatively small percentage of CWIP has a measurable impact on EBIT interest coverage ratios. Based on her observation that the median of CWIP as a per cent of total regulated assets in 2009 for the Alberta utilities was around five per cent, Ms. McShane proposed to include this amount of CWIP in the calculations of equity ratios required to achieve the minimum EBIT coverage ratios observed by the Commission.

200. With respect to the impact of income taxes, Ms. McShane indicated that, in 2012, the combined provincial and federal corporate income tax rate will be 25 per cent, compared to the 29 per cent used in the analysis set out in Decision 2009-216. Furthermore, the Utilities' witness indicated that the median actual effective income tax rate for the taxable Alberta Utilities in 2009 (excluding AltaLink) was less than half the statutory combined rate.[139] As such, Ms. McShane

[136] Decision 2009-216, paragraphs 352, 354 and 356.
[137] AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
[138] Exhibit 86.01, Kathleen McShane Opinion, page 25, lines 638-646.
[139] Ibid., page 27, lines 674-683.

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proposed to use the 12.5 per cent tax rate in equity ratio calculations, which represents 50 per cent of the 2012 statutory tax combined rate of 25 per cent.

201. Incorporating these recommended assumptions regarding the embedded cost of debt, effective tax rate and presence of CWIP,[140] the Utilities provided updated versions of the Commission's analysis of equity ratios in Decision 2009-216 as follows:

Table 8. Credit metrics compared to equity ratios – McShane's evidence

	EBIT coverage		FFO/Debt		FFO coverage	
Equity Ratio	**Table 13 in Decision 2009-216**	**Updated and expanded assumptions**	**Table 14 in Decision 2009-216**	**Updated and expanded assumptions**	**Table 15 in Decision 2009-216**	**Updated and expanded assumptions**
30%	1.8	1.6	12.32	11.71	2.90	2.78
31%	1.9	1.6	12.63	12.00	2.94	2.82
32%	1.9	1.6	12.94	12.29	2.99	2.87
33%	1.9	1.7	13.26	12.60	**3.04**	2.92
34%	2.0	1.7	13.60	12.92	3.09	2.97
35%	**2.0**	1.7	13.94	13.25	3.14	**3.02**
36%	2.1	1.8	**14.30**	13.58	3.20	3.07
37%	2.1	1.8	14.66	13.93	3.26	3.13
38%	2.2	1.9	15.04	**14.29**	3.31	3.18
39%	2.2	1.9	15.43	14.66	3.37	3.24
40%	2.3	1.9	15.83	15.04	3.44	3.30
41%	2.3	**2.0**	16.25	15.44	3.50	3.36
42%	2.4	2.0	16.68	15.85	3.57	3.43
43%	2.4	2.1	17.13	16.27	3.63	3.49
44%	2.5	2.1	17.59	16.71	3.71	3.56
45%	2.6	2.2	18.07	17.16	3.78	3.63
46%	2.6	2.2				
47%	2.7	2.3				

Source: Exhibit 209, Utilities argument, Attachment 2.

202. Based on her evaluation of the net effect of the three adjustments on credit metrics (as presented in Table 8 above), Ms. McShane concluded that an increase in the common equity ratios of no less than two percentage points was warranted. The highlighted examples in the table illustrate that a minimum two percentage point equity ratio increase is necessary to restore the credit metrics to the levels that applied under the 2009 calculations, given Ms. McShane's assumptions.

203. The UCA took issue with the Utilities' inclusion of CWIP and a lower tax rate in the credit metrics calculation. The UCA submitted that, in Decision 2009-216, the Commission implicitly took these factors into account and the resulting equity ratios were well received by the rating agencies. In the UCA's opinion, the relevant facts or circumstances have not changed

140 Utilities' assumptions: embedded cost of debt of 6.4 per cent, ROE of 8.75 per cent, effective tax rate of 12.5 per cent (50 per cent of 2012 statutory tax rate), 5.0 per cent CWIP as percentage of regulated assets, depreciation rate of 6.0 per cent.

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since 2009, and as such, Ms. McShane's analysis was simply an arbitrary re-definition of the Commission's model.[141]

204. The UCA also noted that, in the case of the two transmission utilities that have the highest levels of CWIP – ATCO Electric and AltaLink, the Commission addressed this issue in other ways in their respective GTAs.[142]

205. With respect to Ms. McShane's adjustment related to lower tax rates, the UCA observed that any changes in tax rates affects only the EBIT coverage credit metric, since the FFO/debt and FFO interest coverage metrics are after tax measures. The UCA also submitted that, under a flow-through tax regime, changes in either statutory or effective tax rates do not have any material impact on bondholders or the creditworthiness of the utilities, because the funds collected for taxes on a forecast basis are earmarked for payment to the tax authorities and so are not available to pay creditors.[143]

206. The UCA conceded that lower tax rates reduce the EBIT interest coverage ratio but argued that credit rating agencies do not take the "rigidly rule-based formulaic approach" to understanding credit ratings and credit metrics, and arrive at a balanced assessment of creditworthiness that takes into account all of the moving parts that affect the interests of bond investors.[144] As a result of these considerations, the UCA argued there was no need to update the Commission's credit metric analysis tables in Decision 2009-216.

207. The CCA agreed with the UCA's analysis on CWIP and effective income taxes. Specifically, the CCA argued that there should be no adjustment for income tax rates because deferred income tax must ultimately be paid and financial analysts have not identified deferred income taxes as a risk. In addition, the CCA observed that the effective income tax rate varies greatly from utility to utility and, therefore, any required adjustments should be made on a utility-specific, rather than generic, basis.[145]

208. Similarly, the CCA objected to the across-the-board adjustment for CWIP. The CCA expressed its opinion that a large amount of CWIP is currently a problem for the TFOs but not for all the utilities. The CCA submitted that there is little risk from CWIP and that no adjustment to ROE was necessary for any amount of CWIP.[146]

209. In reply argument, the Utilities submitted that the absence of downgrades does not constitute an appropriate basis for evaluating the reasonableness of Ms. McShane's recommendations and argued that it was necessary to include CWIP amounts in the equity ratio analysis so that the credit metrics identified by the Commission as minimums would be achievable.

210. The Utilities also took issue with the UCA's argument that the income tax allowance is earmarked for payment to the income tax authorities and is not available for payment to creditors. The Utilities submitted that this view does not comport to the manner in which the debt rating agencies evaluate a company's ability to meet its debt obligations. The Utilities explained

[141] Exhibit 210.02, UCA Argument, paragraphs 167 and 173.
[142] Ibid., paragraph 170.
[143] Ibid., paragraphs 178-179.
[144] Ibid., paragraphs 182-184.
[145] Exhibit 211, CCA argument, paragraphs 37-38.
[146] Ibid., paragraph 40.

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that, since interest expense is tax-deductible, income taxes payable are partly a function of how much interest is paid and therefore, it is logical that the debt rating agencies would consider the pre-tax funds that a company has available to cover its debt obligations.[147]

Commission findings

211. In Decision 2009-216, the Commission presented its analysis of equity ratios required to achieve the minimum credit metrics considered to be associated with credit ratings in the A range. The Commission expressly stated that this analysis did not include the consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.[148]

212. In this proceeding, the Utilities pointed out that even a small percentage of CWIP has a measurable impact on credit metrics. As noted in Decision 2009-216, the Commission agrees that the presence of CWIP lowers the credit metrics.[149] In fact, recognizing this reality, the Commission, through its issues list, invited parties to update the credit metric tables with relevant assumptions as to the typical level of CWIP for the Alberta utilities.

213. As discussed further in this section, the Commission agrees with the UCA and the CCA that the adjustment for CWIP is not necessary for ATCO Electric TFO and AltaLink, given that this matter was recently addressed in their respective GTAs. However, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for other Alberta utilities.

214. Specifically, the UCA argued that updating the Commission's tables with typical amounts of CWIP and lower income taxes advocates a formulaic approach to credit metrics. The Commission accepts the UCA's point that rating agencies supplement their analysis of credit metrics with a number of other considerations to arrive at a balanced assessment of a company's creditworthiness. As discussed in Section 5.6 below, the Commission's determination on the matter of capital structure is not limited to credit metric analysis and includes a number of factors such as the current credit environment and the ranking of the utility segments based on business risk.

215. The UCA also argued that no adjustment for a typical level of CWIP and lower income taxes is necessary, since the credit rating agencies appeared to be satisfied with the equity ratios approved in Decision 2009-216, as evidenced by the fact that no utilities have been downgraded since 2009. However, the Commission observes that, due to a number of factors, including the impact of the financial crisis and large capital additions (where applicable), the equity ratios approved in 2009 exceeded the minimum levels indicated by the credit metric analysis in that decision by at least two percentage points.[150] Accordingly, the Commission considers that the favourable reaction of the rating agencies may be attributed to the fact that the last approved equity ratios were sufficient to account for typical amounts of CWIP, not the fact that no adjustment for CWIP was necessary.

147 Exhibit 220.02, Utilities reply argument, paragraph 94.
148 Decision 2009-216, footnote 326 on page 94.
149 Ibid., footnotes 323 and 325.
150 In paragraph 357 of Decision 2009-216, the Commission observed that for an average Alberta utility, the equity ratio associated with the minimum credit metrics would be approximately 34 per cent (34 per cent based on the EBIT analysis, 33 per cent based on the FFO coverage analysis and 30 to 36 per cent based on the FFO/Debt analysis). Table 17 of Decision 2009-216 shows that the minimum equity ratio awarded was 36 per cent.

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216. Regarding the CCA's argument that there is little risk from CWIP and that no adjustment to ROE is necessary for any amount of CWIP, the Commission reiterates that the adjustment to the credit metric calculations in regard to CWIP that was solicited through the issues list was not related to the risk of recovering CWIP balances. Rather, the issue was that CWIP mathematically lowers the credit metrics. The CCA did not address this point.

217. Consequently, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for the Alberta utilities. The Commission has considered the evidence of Ms. McShane that the median of CWIP as a percentage of total regulated assets in 2009 for the Alberta utilities was over five per cent, and finds this number to be a reasonable estimate. The Commission has reflected this level of CWIP in its updated analysis on credit metrics and associated equity ratios, presented in Table 9 below.

218. The Commission also acknowledges the Utilities' evidence that, in 2012, the combined provincial and federal statutory income tax rate will be 25 per cent, as compared to the 29 per cent used in Decision 2009-216. The Commission agrees with Ms. McShane that the income tax rate should be updated in the analysis.

219. In disputing the relevance of lower income tax rates, the UCA submitted that income taxes collected are ear-marked for payment to the tax authorities and so are not available to pay creditors. However, in the event that unforeseen expenses cause profits to decline from the forecast level, the income tax payable would decline and the cash that would otherwise go to taxes would become available to pay interest expenses. Therefore, income taxes collected are in fact partly available to pay creditors in situations where the profit, and therefore the actual amount of income tax payable, is lower than forecast. Additionally, the income tax collected would be fully available to pay interest in the circumstance where profit was zero or negative. Presumably, this is why EBIT (earnings before interest and tax) is important to credit rating agencies and debt investors, rather than simply earnings before interest.

220. However, the Commission does not accept the Utilities' recommendation of using the effective tax rate in the credit metrics analysis. The Commission agrees with the CCA's argument that, because the effective income tax rate varies greatly from utility to utility, any required adjustments should be made on a utility-specific, rather than generic basis. The Commission considers that those utilities that encounter credit rating issues because they are on the flow-through tax method can apply to adopt the future income tax method and thereby collect the full statutory income tax rate. For these reasons, the Commission will use an updated statutory income tax rate of 25 per cent in its analysis below.

221. Using an ROE of 8.75 per cent approved in this decision for 2011 and 2012, and assuming an embedded interest cost of 6.4 per cent, a depreciation rate (as a percentage of invested capital) of six per cent, a tax rate of 25 per cent, and CWIP (as a percentage of rate base) of five per cent, the Commission calculated the key credit metrics and the corresponding equity ratios as follows:

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Table 9. Credit metrics compared to equity ratios – Commission analysis

	EBIT coverage[151]		FFO/Debt (%)		FFO coverage	
Equity ratio	Table 13 in Decision 2009-216	Updated and expanded assumptions	Table 14 in Decision 2009-216	Updated and expanded assumptions	Table 15 in Decision 2009-216	Updated and expanded assumptions
30%	1.8	1.7	12.32	11.73	2.90	2.79
31%	1.9	1.7	12.63	12.03	2.94	2.83
32%	1.9	1.8	12.94	12.32	2.99	2.88
33%	1.9	1.8	13.26	12.63	**3.04**	2.93
34%	**2.0**	1.8	13.60	12.95	3.09	2.98
35%	2.0	1.9	13.94	13.28	3.14	**3.03**
36%	2.1	1.9	**14.30**	13.62	3.20	3.08
37%	2.1	**2.0**	14.66	13.96	3.26	3.13
38%	2.2	2.0	15.04	**14.32**	3.31	3.19
39%	2.2	2.1	15.43	14.7	3.37	3.25
40%	2.3	2.1	15.83	15.08	3.44	3.31
41%	2.3	2.2	16.25	15.48	3.50	3.37
42%	2.4	2.2	16.68	15.89	3.57	3.43
43%	2.4	2.3	17.13	16.31	3.63	3.5
44%	2.5	2.3	17.59	16.75	3.71	3.57
45%	2.6	2.4	18.07	17.21	3.78	3.64

222. Table 9 shows that, given the Commission's assumptions, the minimum equity ratio for Alberta utilities should be 37 per cent based on the EBIT analysis, 30 to 38 per cent based on the FFO/debt analysis and 35 per cent based on the FFO interest coverage analysis. These values show that, as a result of incorporating a typical amount of CWIP and accounting for the lower level of income taxes, the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216.

223. However, as the Commission pointed out earlier in this section, due to a number of factors, including the impacts of the financial crisis and the impact of large capital additions, among others, the equity ratios approved in Decision 2009-216 somewhat exceeded the levels indicated by the credit metric analysis in that decision. In particular, Table 9 above demonstrates that by and large, the currently approved equity ratios of the Alberta utilities meet or exceed the minimum levels determined by the credit metric analysis. In light of these factors, the Commission considers that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is warranted.

151 As discussed in Exhibit 209, Attachment 2 to the Utilities argument, Ms. McShane calculated the EBIT coverage ratios using the S&P methodology, which includes the equity portion of an allowance for funds used during construction (AFUDC) in EBIT component. The Commission used the DBRS methodology, which excludes the equity portion of AFUDC from earnings, resulting in more conservative estimates. However, under the five per cent CWIP assumption, the difference between the two methods is minimal.

5.4 Ranking risk by regulated sector

224. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk affects the perceived uncertainty in future operating earnings and hence determines the capacity for a business to be financed with debt as opposed to equity.

225. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electricity distribution segment was slightly more risky than the electric transmission sector. The Commission agreed that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[152]

226. In the current proceeding, none of the expert witnesses put forward evidence which would indicate materially changed business risks for the utility sectors since Decision 2009-216, with the exception of ATCO Pipelines in light of the integration with Nova Gas Transmission Ltd. (NGTL).

227. In particular, the Utilities recommended no adjustment, generic or company specific, to capital structures due to the recognition of high levels of contributions in aid of construction (CIAC).[153] The Utilities recommended that compensation for high levels of CIAC occur by way of a management fee, as discussed in Section 6 below. The same argument was put forward by the UCA.[154]

228. As well, the Utilities pointed out that their assessment of the business risks upon which their deemed capital structure recommendations was based did not reflect consideration of the potential of changed risks associated with the implementation of a PBR regime in the near future. The Utilities reasoned that, until the specifics of the form of PBR to which any given utility becomes subject are known, a grounded assessment of changes in risk cannot be made.[155]

229. Furthermore, parties to this proceeding submitted that they were not aware of any adjustments to capital structure that would be required to accommodate growth above the historic trend. The UCA submitted that, to the extent that credit related issues have arisen in the context of mandated transmission builds by Alberta TFOs, those have been, or will be, addressed through utility specific measures like including CWIP in rate base or allowing the collection of future income taxes.[156] The Utilities supported this view.[157]

Commission findings

230. The Commission has evaluated the expert evidence of witnesses representing interested parties to this proceeding, and agrees that business risks for Alberta utilities have not changed materially since 2009, with the exception of ATCO Pipelines.

[152] Decision 2009-216, paragraphs 370-371.
[153] Exhibit 209, Utilities argument, paragraph 154.
[154] Exhibit 210.02, UCA argument, paragraph 201.
[155] Exhibit 209, Utilities argument, paragraph 155.
[156] Exhibit 210.02, UCA argument, paragraph 213.
[157] Exhibit 209, Utilities argument, paragraph 156.

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231. Consequently, the Commission reaffirms its findings in the 2009 GCOC decision. In particular, as outlined in Decision 2009-216,[158] the Commission finds that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas.

232. The Commission findings with respect to the impact of CIAC are presented in Section 6 of this decision.

5.5 Further company-specific considerations

233. The Commission now turns to a consideration of further adjustments to the equity ratios of individual companies based on their specific business risks.

5.5.1 Adjustment for non-taxable status

234. In Decision 2009-216, the Commission affirmed the two percentage point adjustment to common equity ratios for non-taxable utilities, initially approved in Decision 2004-052, on the basis of higher earnings volatility and a negative impact on credit metrics. This adjustment applied to ENMAX and EPCOR utilities and was extended to FortisAlberta, since at the time of the 2009 GCOC decision FAI anticipated being a non-taxable entity until at least 2013.[159]

235. In this proceeding, Ms. McShane noted that, to fully reflect the impact of non-taxability on pre-tax interest coverage ratios, the common equity adjustment would need to be six per cent. Notwithstanding this, the Utilities submitted they supported the findings of the Commission and its predecessor that two percentage points increase is warranted and recommended that this adjustment for non-taxable status continue to apply.[160]

236. Ms. McShane also indicated that, based on FortisAlberta's assessment, it will collect zero income taxes in rates through at least 2016 and, therefore, FortisAlberta remained a de facto non-taxable entity for purposes of this proceeding.[161] As such, in this proceeding, each of the non-taxable utilities (ENMAX and EPCOR as legally non-taxable and FortisAlberta as de facto non-taxable) were seeking a deemed capital structure that continued the treatment established in Decision 2009-216 and Decision 2004-052.

237. The UCA submitted that the additional two per cent equity thickness that has been provided to non-taxable utilities due to their higher earnings volatility was not reasonable or necessary. Specifically, the UCA indicated that the argument regarding increased earnings volatility assumes that any variance in earnings is symmetrical when in fact over-earning is more common. Relying on the data on historical earned ROEs relative to allowed ROEs provided by the Commission in Exhibit 161, the UCA submitted that Alberta utilities are more likely to over-earn their allowed returns than to under-earn, and the benefit of the same amount of over-earning increases with a lower tax rate.[162]

158 Decision 2009-216, paragraphs 370-371.
159 Decision 2009-216, paragraphs 383-384.
160 Exhibit 209, Utilities argument, paragraph 141.
161 Exhibit 86.01, Kathleen McShane Opinion, page 32, lines 812-817.
162 Exhibit 210.02, UCA Argument, paragraphs 190-193.

required between two regulated utilities which already have underlying obligations to provide service; examine the potential impact on becoming a direct connect customer if distribution facilities owners do not have to make contributions in the future; and, investigate the means of mitigating any impacts. For these reasons, the Commission will not direct the DFOs take up Rider I at this time.

7.3.2 Implementation for TFOs

549. Finally, with respect to the implementation of Rider I and its effects on the revenue requirements of the TFOs, the Commission notes that all parties except the Utilities argued that there would need to be additional filings with the Commission in order to adjust the revenue requirements of the TFOs. The Utilities suggested that Rider I payments be flowed through directly to the TFOs. Given the uncertainty of the uptake of Rider I, the Commission agrees with the AESO that it would create unnecessary administrative procedures to flow through the Rider I payments directly to the TFOs. The Commission agrees with the AESO that, during the first two years of Rider I implementation, the TFOs can accommodate increases to revenue requirements due to Rider I through a Rider I deferral account. After this period, the TFOs should be able to reasonably forecast their revenue requirement without a Rider I deferral account and can adjust their revenue requirement in their respective GTAs. The Commission therefore approves deferral account treatment for the impacts of Rider I on the TFO revenue requirements for the years 2012 and 2013.

8 Order

550. It is hereby ordered that:

(1) The Generic ROE for 2011 and 2012 is set at 8.75 per cent.

(2) The Generic ROE for 2013 is set at 8.75 per cent on an interim basis.

(3) Equity ratios for the Alberta utilities for 2011 and 2012, and until further changed by the Commission, are as set out in the table below.

(4) Rider I is approved in principle. The Commission directs the AESO to file a separate Rider I tariff application which will give effect to this approval based on the findings in this decision.

(5) The Utilities' request for a management fee as compensation for the provision of service involving assets funded by CIAC is denied.

(6) Utilities are directed to apply to adjust their revenue requirements to reflect the impacts of this decision in due course.

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	Last approved (%)	Approved (%)
Electric and Gas Transmission		
ATCO Electric TFO	36	37
AltaLink	36	37
ENMAX TFO	37	37
EPCOR TFO	37	37
RED Deer TFO	37	37
Lethbridge TFO	37	37
TransAlta	36	36
ATCO Pipelines	45	45 for 2011 38 for 2012
Electric and Gas Distribution		
ATCO Electric DISCO	39	39
ENMAX DISCO	41	41
EPCOR DISCO	41	41
ATCO Gas	39	39
FortisAlberta	41	41
AltaGas	43	43

Dated on December 8, 2011.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Panel Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Mark Kolesar
Commission Member

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CONCENTRIC

Equity Thickness Evaluation and Recommendation

Prepared for:
Enbridge Gas Distribution

January 27, 2012

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percentage point increase in the equity ratio to 43.5 percent, impacting rates by ($4.0 billion x (7.5% additional equity x 9.42% cost of equity[33]/(1 - .35 tax rate), less 7.5% debt x .06).[34]

As this analysis shows, the cost to ratepayers of a ratings downgrade may be equivalent to a fairly significant increase in equity. However, the financial integrity of the utility would be far superior under the increased equity scenario than enduring the debt cost impact of a ratings downgrade. An increase in the equity ratio will in the long term promote financial flexibility and the ability to endure changing economic conditions allowing the Company to maintain its financial integrity as required by the Fair Return Standard.

C. Comparison of Equity Ratios among North American Gas Distribution Utilities

To put EGDI's equity thickness of 36 percent into context, Concentric researched SNL Statistics for the population of all U.S. regulatory awards for gas utilities over the period 2000 to present.[35] The average is represented by the dotted line in Figure 6. In addition, Concentric gathered equity ratio data for all of the major gas distribution utilities in Canada (the average is the central solid line in Figure 6). As Figure 6 shows, EGDI's allowed common equity ratio of 36 percent is well below the average annual equity ratios awarded to both Canadian and U.S. natural gas distribution utilities. Presently, the Canadian average equity ratio (excluding EGDI in Ontario) is 40.96 percent[36] and the

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33 This analysis assumes that EGDI will be awarded the formula rate of return upon filing its application, currently at 9.42%.

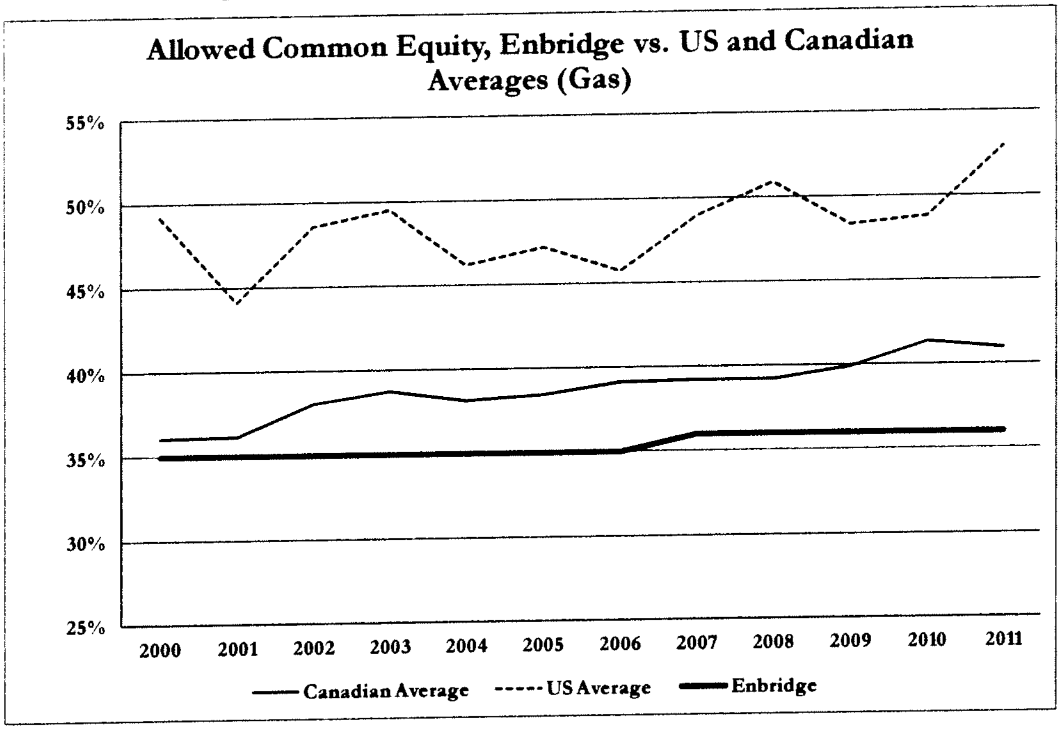
34 The calculation on an "after-tax" basis would be as follows: on a rate base of approximately $4.0 billion, and a debt cost of 6.0%, a ratings downgrade leading to a 100 bps increase in the cost of debt would increase rates by approximately $16.64 million ($4.0 billion x .64 debt ratio x (100 bps x (1 – .35 tax rate))), a result which costs ratepayers as much as a 7.5 percentage point increase in the equity ratio to 43.5 percent ($4.0 billion x (7.5% additional equity x 9.42% cost of equity, less 7.5% debt x (.06 * (1 - .35 tax rate)).

35 This data includes all regulatory proceedings covered by Regulatory Research Associates (RRA) for approximately 106 U.S. gas utilities and 361 regulatory proceedings of which 251 regulatory proceedings specified an equity thickness. RRA is a proprietary data base that may be accessed through a subscription to SNL Interactive.

36 The average excluding Union Gas would be 41.41 percent. The Canadian Average includes Alta Gas Utilities (43.0%), ATCO Gas (39.0%), Enbridge Gas New Brunswick (45.0%), FortisBC Energy Terasen Gas (40.0%) Terasen Gas Vancouver Island (40.0%) Terasen Gas Whistler (40.0%), Gaz Metro (38.5%), Heritage Gas (45.0%), Pacific Northern Gas Western Division (45.0%) Fort St. John/Dawson Creek Division (40.0%) Tumbler Ridge Division (40.0%) and Union Gas (36.0%).

U.S. average equity ratio is 52.84 percent.[37] In fact, EGDI's equity ratio is the lowest in the industry, along with Union's, at 36 percent.

Figure 6: Allowed Common Equity Ratios (2000-2011)



Sources: Average equity ratio data for US gas companies as recorded by SNL Regulatory Research Associates. Canadian average determined by Concentric.

Looking beyond the averages for all Canadian and U.S. companies, we have developed a proxy group of companies having comparable risks to EGDI at the regulated entity level. This yields a different group of companies than those that we used to develop our ROE analysis. Note however, that we have established that the proxy group used for developing our ROE analysis was capitalized at an average of 49.9 percent equity, well above that of EGDI at 36 percent.

We have screened at the regulated entity level as opposed to the holding company level for purposes of this analysis in order to perform an apples to apples comparison of risks and returns across a group of regulated North American gas utilities, specifically selected to reflect the risks of EGDI at

[37] U.S. average gas company equity ratio as calculated by SNL Regulatory Research Associates and represents the average common equity ratio authorized in gas rate cases, updated on a quarterly basis. The average allowed common equity ratio for 2011 of 52.84 is the result of averaging the allowed common equity ratios from the first and second quarters of that year, 52.47% and 53.21%, respectively. This represents rulings in seven rate cases.

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the operating level. This group is necessarily different than the group of holding companies we selected for our ROE analysis, because although the consolidated profile of the holding company may be comparable to EGDI relative to other holding companies, its operating entities may not be comparable. Secondly, one can go beyond screens that are necessary and appropriate for a cost of capital analysis to analyze comparability at the regulated entity level, i.e. at the utility operating company level. By removing those constraints and screening at the regulated entity level, we add another perspective to the comparability of EGDI's equity thickness relative to its peers. The results of this analysis are described in Appendix B.

After performing this operating risk analysis for each company, Concentric assigned an overall risk rating by weighing each of the four risk categories equally. Of the 10-company proxy group (operating in 15 separate jurisdictions), 8 operating companies were rated as having approximately equal risk to EGDI, while 7 operating companies were rated as having less risk than EGDI. No companies were rated as having more risk than EGDI. On average, EGDI's risk profile is comparable to the average North American comparable group member, albeit slightly more risky. However, although EGDI's risk profile is in-line with the proxy group component companies, as the chart below shows, EGDI's allowed common equity is markedly below those of its peers, both in terms of ROE and equity thickness, and has been so for over a decade.

Approved Common Equity Ratios
Canadian Utilities
2003, 2006, 2009, 2011

Line	Company	2003	2006	2009	2011
1	AltaGas	41.0%	41.0%	43.0%	43.0%
2	ATCO Electric Disco	35.0%	37.0%	39.0%	39.0%
3	ATCO Gas	37.0%	38.0%	39.0%	39.0%
4	Enbridge Gas Distribution	35.0%	35.0%	36.0%	36.0%
5	ENMAX Disco	39% [1]	39.0%	41.0%	41.0%
6	EPCOR Disco	39% [1]	39.0%	41.0%	41.0%
7	FortisAlberta	40.0%	37.0%	41.0%	41.0%
8	FortisBC Energy/Terasen Gas	33.0%	35.0%	35.0%	40.0%
9	Gaz Metro	38.5%	38.5%	38.5%	38.5%
10	Gaziféré	40.0%	40.0%	40.0%	40.0%
11	Heritage Gas	45.0%	45.0%	45.0%	45.0%
12	Nova Scotia Power	45.0%	45.0%	45.0%	45.0%
13	Pacific Northern Gas, Ltd. Western Division	36.0%	40.0%	40.0%	45.0%
14	**Average**	**38.7%**	**39.2%**	**40.3%**	**41.0%**
15	**Union Gas Limited**	**35.0%**	**35.0%**	**36.0%**	**36.0%**

[1] ENMAX and EPCOR only came under Board's jurisdiction Jan. 1, 2004. Figures shown are 2004.

Allowed Return on Equity												
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
AltaGas	11.75%	11.75%	9.70%	9.50%	9.50%	9.50%	8.93%	8.51%	8.75%	9.00%	9.00%	9.00%
ATCO Gas	N/A	9.50%	9.50%	9.50%	9.50%	9.50%	8.93%	8.51%	8.75%	9.00%	9.00%	9.00%
Enbridge Gas Distribution	9.73%	9.54%	9.66%	9.69%	9.69%	9.57%	8.74%	8.39%	8.39%	8.39%	8.39%	8.39%
Enbridge Gas NB	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	10.90%
FortisBC Energy												
Terasen Gas	9.50%	9.25%	9.13%	9.42%	9.15%	9.03%	8.80%	8.37%	8.62%	8.47%	9.50%	9.50%
Terasen Gas Vancouver Island	N/A	N/A	N/A	N/A	9.65%	9.53%	9.50%	9.07%	9.32%	9.17%	10.00%	10.00%
Terasen Gas Whistler	N/A	N/A	N/A	N/A	9.75%	9.63%	9.40%	8.97%	9.22%	8.97%	10.00%	10.00%
Gaz Metro	9.64%	9.60%	9.67%	9.89%	9.45%	8.95%	8.95%	8.73%	9.05%	8.76%	9.20%	9.09%
Heritage Gas	N/A	N/A	N/A	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
Pacific Northern Gas, Ltd.												
Western Division	10.25%	10.00%	9.88%	10.17%	9.80%	9.68%	9.45%	9.02%	9.27%	9.12%	10.15%	10.15%
Fort St. John/Dawson Creek Division	10.00%	9.75%	9.63%	9.82%	9.56%	9.43%	9.20%	8.77%	9.02%	8.87%	9.90%	9.90%
Tumbler Ridge Division	10.25%	10.00%	9.88%	10.07%	9.80%	9.68%	9.45%	9.02%	9.27%	9.12%	10.15%	10.15%
Union Gas Limited	9.61%	9.95%	9.95%	9.95%	9.62%	9.62%	9.63%	8.54%	8.54%	8.54%	8.54%	8.54%
*Revised Ontario Formula**										*9.75%*	*9.85%*	*9.66%*

* *Note: Enbridge Gas Distribution and Union Gas are subject to 5-year performance based rate plans in Ontario, with fixed ROE's established in 2007 according to the Ontario formula which prevailed at that time. In 2009, the Ontario Energy Board revised its formula, and has since issued annual updates. Both utilities will be eligible to apply for the new formula when they re-base rates for 2012. The new formula rate is reported here for reference. The ROE figures reported here exclude any earnings sharing.*

Allowed Common Equity Ratio

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AltaGas	24%	24%	41%	41%	41.00%	41.00%	41.00%	41.00%	41.00%	43.00%	43.00%	43.00%
ATCO Gas	N/A	37.00%	37.00%	37.00%	37.00%	38.00%	38.00%	38.00%	38.00%	39.00%	39.00%	39.00%
Enbridge Gas Distribution	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Enbridge Gas NB	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	45.00%
FortisBC Energy												
Terasen Gas	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	35.00%	35.00%	35.01%	35.01%	40.00%	40.00%
Terasen Gas Vancouver Island	N/A	N/A	N/A	N/A	35.00%	35.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Terasen Gas Whistler	N/A	N/A	N/A	N/A	35.00%	35.00%	35.00%	35.00%	35.00%	40.00%	40.00%	40.00%
Gaz Metro	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%	38.50%
Heritage Gas	N/A	N/A	N/A	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Pacific Northern Gas, Ltd.												
Western Division	36.00%	36.00%	36.00%	36.00%	36.00%	N/D	40.00%	40.00%	40.00%	40.00%	45.00%	45.00%
Fort St. John/Dawson Creek Division	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	40.00%	40.00%
Tumbler Ridge Division	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	40.00%	40.00%
Union Gas Limited	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Average	35.94%	36.05%	37.75%	38.41%	37.88%	38.13%	38.81%	38.96%	38.96%	39.58%	40.96%	[redacted]
Average without EGDI	36.06%	36.17%	38.06%	38.75%	38.13%	38.41%	39.13%	39.21%	39.21%	39.88%	41.38%	40.96%

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RP-2003-0063
EB-2003-0087
EB-2003-0097

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

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UNION GAS LIMITED
Calculation of Requested and Approved Rate of Return
Calendar Year Ending December 31, 2004

		As Filed			Per Board		
Line No.	Particulars ($000's)	Capital Structure (a)	Cost Rate (%) (b)	Requested Return (c)	Capital Structure (a)	Cost Rate (%) (b)	Return (c)
1	Long-term debt	$ 2,009,458	8.45%	$ 169,799	2,009,458	8.45%	169,799
2	Unfunded short-term debt (1)	(130,778)	4.15%	(5,427)	(118,494)	4.15%	(4,917)
3	Total debt	1,878,680		164,372	1,890,964		164,882
4	Preference shares	109,539	5.44%	5,959	109,539	5.44%	
5	Common equity	1,070,579	11.63%	124,455	1,070,579	9.62%	102,990
6	Utility rate base	$ 3,058,798		$ 294,786	3,071,082		267,871

Note:
(1) "Per Board" reflects Board's rate base adjustment on Schedule 2

EB-2005-0520

UNION GAS LIMITED

SETTLEMENT AGREEMENT

May 15, 2006

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UNION GAS LIMITED
Summary of Cost of Capital
Year Ending December 31, 2007

Line No.	Particulars		Utility Capital Structure ($000's)	(%)	Cost Rate %	Requested Return ($000's)
			(a)	(b)	(c)	(d)
			As Filed			
1	Long-term debt	$	2,090,667	61.27	7.68%	160,559
2	Unfunded short-term debt		(152,817)	(4.48)	3.16%	(4,831)
3	Total debt		1,937,850	56.79		155,728
4	Preference shares		109,469	3.21	4.71%	5,161
5	Common equity		1,364,880	40.00	9.63%	131,438
6	Total rate base	$	3,412,199	100.00		292,327
			As Per Settlement Agreement			
7	Long-term debt (1)	$	2,082,334	61.66	7.66%	159,403
8	Unfunded short-term debt (2)		(30,396)	(0.90)	1.55%	(472)
9	Total debt		2,051,938	60.76		158,931
10	Preference shares		109,469	3.24	4.71%	5,161
11	Common equity (3)		1,215,792	36.00	9.63%	117,081
12	Total rate base (4)	$	3,377,199	100.00		281,173
13	Change		(35,000)			(11,154)

Notes:
(1) Reflects updated interest rate forecast for 2006 as at March '06 , no new issues after Sept 2006
(2) Reflects updated interest rate forecast for 2007 as at March '06 and increase in standby charges to $800K
(3) Reflects 36% common equity
(4) Relects a reduction of $35 million in rate base